On Grid-Serving Grid Tariff Design in Local Energy Markets

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***Abstract*—Local Energy Markets (LEMs) are virtual market places that allow for energy sharing of prosumers in proximity to each other. In LEMs, participants' offers and bids are coordinated by a pricing mechanism, which sets price signals for generation and loads. This impacts distribution grid utilization. Dynamic grid fees could be used by the distribution system operator to add price signals for market participants that are beneficial to the distribution grid operation. To develop such a grid-serving LEM design, we propose a framework for the design of alternative grid tariffs as a trade-off between cost-reflective and cost-recovering grid tariffs. We analyze three alternative grid tariff components in the context of LEMs: time-varying energy fees, critical peak pricing (CPP) and capacity fees for power not traded on the LEM. A case study on a synthetically generated grid region shows that while the alternative tariff components can reduce the aggregated peak load of the region by up to 31 % with the CPP, the fees can also lead to increased line utilization. Also, while total local added value can be increased with all alternative grid tariffs, especially capacity-based grid tariffs are connected to a strong redistribution of grid costs from flexible to inflexible prosumers.**

***Index Terms*—dynamic grid tariff, energy communities, energy sharing, grid tariff design, local energy market**

I. Introduction

With the concept of Energy Sharing within Energy Communities, the EU has created a legal framework in the Directive (EU) 2018/2001 (RED II) [1] for the energy exchange of prosumers in proximity to each other. The concept shall create local added value through active participation of end customers in the energy sector and with it increase social acceptance for the transformation of the energy sector [2], [3]. Energy Sharing requires coordination of local supply and demand [3]. One possible approach is given by the implementation of virtual market places on which local electricity can be traded. In research, different designs for these market places are summarized under the term "Local Energy Markets" (LEMs) [4].

In LEMs, participants offers and bids are coordinated by a pricing mechanism, which sets price signals for flexible demand and generation to shift operation into low respectively high price periods. This impacts distribution system utilization: On the one hand, local balancing can reduce the utilization of higher grid levels and transformers by shifting demand from peak load periods to periods with high local generation [2], [3]. On the other hand, an unequal distribution of loads and generators in the distribution grid can lead to increased utilization of certain grid feeders [5].

The increased implementation of information and communication technology in distribution grids allows for a more precise monitoring of the grid making it possible to develop a grid-serving LEM design. For example, dynamic grid fees based on the current grid utilization could be used by the distribution system operator to add price signals for market participants that are beneficial to the distribution grid and reduce grid utilization and congestion.

Literature on the presented topic can be divided in three domains: *General LEM Design and Impact*, *Grid-Serving LEM Design*, and *Alternative Grid-Tariff Design*. Several papers [2], [3], [5] have discussed the *general design and impact of LEMs* without considerung grid-serving design alternatives. [2] performed a German case to study the impact of LEM designs on local added value, the level autarky level of the market as well as the aggregated load in multiple grid regions without modelling the distribution grid. [3] analysed the impact of an LEM-rollout in Germany and France on transmission grid congestions. [5] analysed the impact of a peer-to-peer LEM on the distribution grid utilization without considering grid-serving LEM design alternatives.

The *design of grid-serving LEMs* has been discussed in [6], [7], [8], [9]. [6] comprehensively reviewed grid impact and and grid-serving design alternatives without discussing the effect of these designs on market participants and the local added value. [7] proposed a grid-serving LEM design including power line capacity factors in the market clearing process without considering dynamic grid designs and without analyzing the impact on local added value. [8] analysed the load shifting effects of an LEM with a transaction-based grid tariff design using substation and feeder fees without addressing distribution grid utilization. Since both designs require insight into the distribution grid operation during market clearing, we propose alternative methods via price signals given to the energy community by the grid operator without requiring insight into grid operation. [9] compared different grid tariff alternatives in LEMs regarding their impact on the aggregated peak load and costs benefits for different asset types without addressing further impacts on grid operation such as line utilization.

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Alternative grid-tariff designs are discussed in [10], [11], [12], [13] without implementing them in LEMs. [10] defined key principles of grid tariff design and dimensioning without analysing the impacts of alternative grid tariff designs. [11] evaluated alternative energy- and capacity-based grid fee components qualitatively without quantifying the impact. [12] analysed change of energy costs for customers when shifting from energy- to capacity-based grid tariffs without analysing the grid impact. [13] analysed the demand response of alternative capacity-based grid tariffs without considering time-varying energy fees.

From the literature review, it remains unclear how alternative energy-based and capacity-based grid tariff designs can influence the market price on LEMs and with that the level and distribution of local added value among market participants. Therefore, we develop a methodology for the evaluation of alternative grid tariff designs in LEMs and investigate the impact of different design options of dynamic grid tariffs in LEMs on grid operation as well as the level and distribution of local added value among market participants in an exemplary study.

For this purpose, we first construct a framework for the design of alternative grid tariffs. The grid tariff design framework constitutes a trade-off between cost-reflective and cost-recovering grid tariffs by combining general tariff design principles in Germany with existing results of cost driver analyses in research. The developed framework is then used to create multiple alternative grid tariff structures which can be implemented in LEMs. The developed framework for grid-serving grid tariff designs as well as the methodology for their evaluation in LEMs are applied in an exemplary study.

II. Analysis

A. Definition of the LEM

The concept of LEMs cover a range of designs for localized digital market platforms for trading locally generated energy [4]. In this paper, we assume a central day-ahead auction using merit order with hourly energy products. Participation is limited to households, as well as small and medium sized businesses in one distribution grid. Participants can choose at any time between a conventional energy supplier (hereafter referred to as backup utility or BU) and the LEM to buy or sell energy. To increase liquidity of the LEM participants do not have to pay electricity tax for energy bought on the LEM. [2]

B. Conventional and Alternative Grid Tariff Components

In Germany, grid fees are only paid for consumed energy. The design of the grid tariffs is regulated by the German federal network agency with limited degrees of freedom for the grid operator in the dimensioning of the grid fees. The grid tariffs for residential and commercial users can consist of the following three components:

- **Static energy fee**: Flat-rate fee paid for each kilowatt-hour consumed during the accounting period
- **Capacity fee**: Fee paid for the peak demand in kilowatt by a grid user during the accounting period
- **Fix fee**: Fee paid by the grid user per accounting period for the grid connection independent of their consumption

Typically, residential users pay a static energy fee and a fix fee, while commercial users pay a capacity fee instead of a fix fee. The grid fees are dimensioned based on the assumption that the aggregated peak load of the consumers drives the grids main costs. However, while the energy fee minorly incentives to increase self-consumption and the capacity fee sets the incentive to reduce the individual peak load, none of the components directly creates a grid-serving incentive to reduce load during high load periods. Therefore, alternative grid tariff designs that shell set varying price signals for the customers are required for a grid-serving LEM design. Key principles that need to be taken into account for grid tariff designs include the *economic sustainability* ensuring that the grid operator can fully recover the grid costs from their revenues, *economic efficiency* ensuring that the grid fees set price signals that impact relevant cost drivers as well as *non-discrimination* and *acceptance*, *transparency*, *complexity* and *predictability* for consumers. The first two principles will be focus of this paper while the later are discussed qualitatively for the alternative grid tariffs.

In this study we analyze the following three alternative components that shall incentivize the reduction of the aggregated peak load extracted from the transmission grid:

- **Time-varying energy fee**: Energy fee which increases during periods with high load and decreases during periods with low load or high generation. Economic efficiency, acceptance, transparency, predictability and complexity of this component depend on the frequency in which the fee changes and the time horizon in which the users are informed about future fees. While a fix set of high and low price periods increases transparency, it also decreases the economic efficiency of the fee since the fee may create wrong incentives in periods deviating from the norm.
- **Critical Peak Price (CPP)**: The CPP directly sets a price for the aggregated peak load in the grid region within the accounting period of the fee. Each grid consumer has to pay the fee for each kilowatt contributed to the peak load. While this fee is highly economic efficient due to the direct pricing of a main cost driver, transparency and predictability for consumers is low since the fee is highly dependent on the consumption of other consumers. This may also decrease the acceptance of the fee. In this study, we analyze a CPP that sets a price for the peak load at the hv-mv transformer meaning LEM trade is unaffected by this fee.
- **LEM-excluding capacity fee**: This fee is similar to a conventional capacity fee but only affects consumption outside of the LEM, i.e. from conventional energy suppliers. This may increase the incentive to reduce peak load at the hv-mv transformer since not only flexible users can reduce their backup load by shifting load but also inflexible users by trading on the LEM. While economic

efficiency is limited due to the limited correlation between individual and aggregated peak load, this grid fee is more transparent and predictable for consumers than the CPP since their grid fees are only dependent on their individual consumption. In the following, this fee is referred to backup capacity fee.

III. Methodology

A. Energy System Modelling

In order to simulate and investigate LEMs in a distribution system for the purpose of this paper, we use and expand an existing energy system model for LEMs consisting of a simulation model for a LEM and a power flow calculation based on the market results of the LEM simulation.

The market simulation is based on the model of a central day-ahead coordinator having perfect foresight described in [2]. In this, a market coordinator maximizes social welfare SW defined as the aggregation of each market participant's economic benefit for one simulated day. It is determined by the sum of the contribution margins CM_i^m of all market participants $i \in I$ of every marketing option $m \in M$, i.e. BU, and LEM, in every time step $t \in T$:

$$max\ SW = \sum_{t \in T} \sum_{i \in I} \sum_{m \in M} CM_{i,t}^m. \tag{1}$$

The contribution margin $CM_{i,t}^m$ of a market participant i in time step t is defined as the revenue from the market options m less its costs and can be determined as follows:

$$CM_{i,t}^m = p_{i,t}^m \cdot E_{i,t}^{m,sale-buy} - c_{i,t}^{levy_m} \cdot E_{i,t}^{m,buy}, \tag{2}$$

where $E_{i,t}^{m,buy}$ is the energy purchased, and $E_{i,t}^{m,sale-buy}$ is the energy sold minus the energy purchased of the marketing option m by the market participant i in time step t, $p_{i,t}^m$ is the energy price of the marketing option m for the customer i in time step t, and $c_{i,t}^{levy_m}$ are the additional taxes and levies connected to the buying option. The market coordination is subject to individual dispatch constraints of each market participant as well as the balancing of supply and demand on the market resulting from each participant's dispatch model via an LEM coupling constraint. Further details to the constraints can be found in [2]. In Fig. 1 the structure of the optimization problem (OP) is shown schematically.

This model for local trading is equivalent to that of a central uniform pricing auction under the assumptions of full information and perfect competition. To minimize simulation time, the OP is formulated as a linear problem. Moreover, to represent a day-ahead market the optimization is performed separately for each day of the year in a rolling time horizon [2].

The power flow calculation is performed with the open-source software tool MATPOWER for MATLAB using the Newton-Raphson method as described in [14], [7]. The hv-mv transformer represents the slack node of the distribution grid. The customer nodes are modeled as PQ nodes. The active power injection or withdrawal is determined for each customer node by aggregating the dispatch schedules of all generation and load units of the customer from the result of the market simulation. The respective reactive power injection or withdrawal of the node is determined via constant power factors $cos\phi$ for each generation and load unit connected to the node. Here, a distinction is made between inflexible loads from the customer's base demand and flexible loads or distributed generation plants which can also control their reactive power to some extend. Inflexible loads receive a $cos\phi$ of 0.99 inductive. The reactive power control of flexible loads and distributed generation plants is set to counteract their active power behavior with their reactive power behavior. That is, flexible loads inject voltage-increasing inductive reactive power to compensate for the voltage decreasing effect of the load, while generation plants inject voltage-lowering capacitive reactive power. The power factor according to the usual consumer arrow system for these plants is set to 0.95 inductive (for distributed generation plants) or 0.95 capacitive (for flexible loads). The reactive power control via a fixed power factor within this model has first been described in detail in [7].

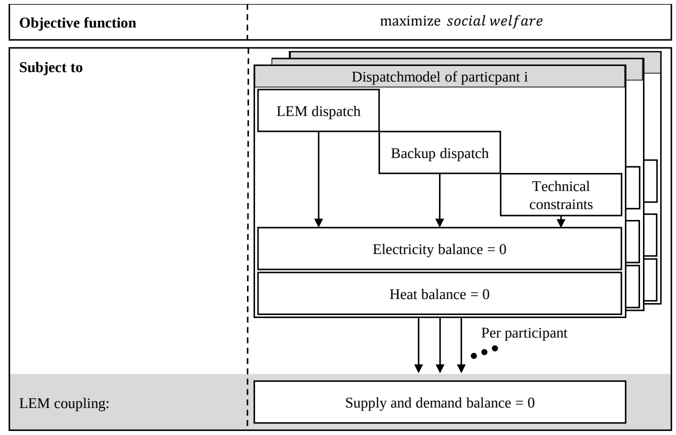


Fig. 1. Schematic diagram of the basic model of the OP [2]

B. Grid Tariff Component Modelling

In this paper, we simulate multiple scenarios with alternative grid tariff components. The scenarios include static and time-varying energy fees, CPP as well as conventional and backup capacity fees. To model these alternative grid tariff components, we extend the LEM simulation model seen in Fig. 1.

Energy fees fee^{energy} can already be included with the basic model by adding them to the other taxes and levies $c_{i,t}^{levy_{BU}}$ or $c_{i,t}^{levy_{LEM}}$. Sector-specific or location-dependent energy fees can be represented through individual prices per market participant $i \in I$. Time-varying energy fees require an additional dependency on the time period $t \in T$. We assume a minimum lead time for the definition of time-varying fees of one day. Therefore, since perfect foresight is assumed in this work, an ex-ante determination of the values $fee_{i,t}^{energy_{BU}}$ and $fee_{i,t}^{energy_{LEM}}$ $\forall i \in I,\ \forall t \in T$ is sufficient and no dynamic adjustment of the time-varying energy fee during optimization is needed.

The CPP fee^{CCP} can be implemented in the simulation model via a pricing of the maximum aggregated withdrawal from the BU over all market participants $P^{BU}_{max,tot}$. $P^{BU}_{max,tot}$ results from the aggregation of all backup energy purchases $E^{BU_{buy}}_{i,t}$ and sales $E^{BU_{sale}}_{i,t}$ of a time period, as follows [2]:

$$P^{BU}_{max,tot} = \max_{t \in T} \left(\sum_{i \in I} \frac{E^{BU_{buy}}_{i,t} - E^{BU_{sale}}_{i,t}}{\Delta t},\ 0 \right), \quad (3)$$

where the time step length Δt is used to convert energy flows per kilowatt-hour into power flows per kilowatt. $P^{BU}_{max,tot}$ is here limited downward by zero to prevent gains in the objective function by increasing backup sales $E^{BU_{sale}}_{i,t}$. 3 is valid provided that the entire accounting period $d = 1...D$ for the CPP is simulated in one optimization step. However, since in this work the OP is solved on a rolling basis for each day d in the simulation period, the previous maximum withdrawal $P^{BU}_{max,tot,d-1}$ must be taken as the lower bound for $P^{BU}_{max,tot,d}$ in the iteration $d = 2...D$. Therefore, for $d \geq 2$ holds:

$$P^{BU}_{max,tot,d} = \max_{t \in T} \left(\sum_{i \in I} \frac{E^{BU_{buy}}_{i,t} - E^{BU_{sale}}_{i,t}}{\Delta t},\ P^{BU}_{max,tot,d-1} \right). \quad (4)$$

The CPP results in the costs K^{CCP}_{d}, which are included as an additional cost component in the objective function of each simulation period d [2] defined as:

$$K^{CCP}_{d} = fee^{CCP} \cdot P^{BU}_{max,tot,d} \quad (5)$$

The actual accounted costs of the CPP, i.e. the income for the grid operator, is then given by the cost component K^{CPP}_{D} at the end of the accounting period. The cost K^{CPP}_{i} by the CPP for each end user i is then defined by the consumer's backup energy purchase $E^{BU_{buy}}_{i,t^{CPP}}$ at time t^{CPP} of the grid peak load $P^{BU}_{max,tot,D}$:

$$K^{CPP}_{i} = fee^{CCP} \cdot E^{BU_{buy}}_{i,t^{CPP}}, \forall i \in I. \quad (6)$$

This model is consistent with the assumption that participants know the previous peak load and act accordingly, but can only predict the future grid load for the next day.

The conventional capacity fee $fee^{capacity}$ and the backup capacity fee $fee^{BU\text{-}capacity}$ can be inserted into the OP in a similar way as the CPP. However, the constraints for $fee^{capacity}$ and $fee^{BU\text{-}capacity}$ are implemented in the dispatch planning model of each individual market participant. The relevant power flow for the conventional capacity fee and the backup capacity fee is the total power flow $P^{tot}_{max,i}$ and backup energy flow $P^{BU}_{max,i}$, respectively, of the participant $i \in I$. Analogous to (5), (3), and (4), the cost component $K^{capacity}_{i}$ of participant $i \in I$ from the conventional capacity fee $fee^{capacity}$ in the objective function of a simulation period from 1 to D is:

$$K^{capacity}_{i,d} = fee^{capacity} \cdot P^{tot}_{max,i,d} \quad (7)$$

$$P^{tot}_{max,i,1} = \max_{t \in T} \left(\sum_{m \in M} \frac{E^{m,buy-sale}_{i,t}}{\Delta t},\ 0 \right), \quad (8)$$

$$P^{tot}_{max,i,d} = \max_{t \in T} \left(\sum_{m \in M} \frac{E^{m,buy-sale}_{i,t}}{\Delta t},\ P^{tot}_{max,d-1} \right), \ \forall d \geq 2, \quad (9)$$

and for backup capacity fee $fee^{BU\text{-}capacity}$:

$$K^{BU\text{-}capacity}_{i,d} = fee^{BU\text{-}capacity} \cdot P^{BU}_{max,i,d} \quad (10)$$

$$P^{BU}_{max,i,1} = \max_{t \in T} \left(\frac{E^{BU,buy-sale}_{i,t}}{\Delta t},\ 0 \right), \quad (11)$$

$$P^{BU}_{max,i,d} = \max_{t \in T} \left(\frac{E^{BU,buy-sale}_{i,t}}{\Delta t},\ P^{BU}_{max,d-1} \right), \ \forall d \geq 2 \quad (12)$$

The actual accounted cost by the conventional capacity fee $K^{capacity}_{i}$ or the backup capacity fee $K^{BU\text{-}capacity}_{i}$ for customer i is fixed after full simulation of the settlement period and is defined by:

$$K^{capacity}_{i} = fee^{capacity} \cdot P^{tot}_{max,i,D} \quad (13)$$

$$K^{BU\text{-}capacity}_{i} = fee^{BU\text{-}capacity} \cdot P^{BU}_{max,i,D}. \quad (14)$$

A fixed cost component of the grid tariff has no impact on the (short-term) dispatch in the market region and, thus, does not need to be included in the OP. The cost will be added to the total and individual costs per market participant after the simulation.

C. Dimensioning of Grid Tariff Components

The proccess for the dimensioning of grid tariffs is shown in Fig. 2. Inputs for the dimensioning are a *cost driver analysis* as well as one simulated business-as-usual scenario with the current grid tariff design in germany (*BAU scenario*) and one *scenario without grid tariffs*. The whole process is described in the following.

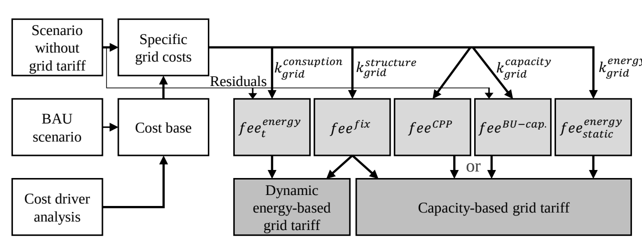


Fig. 2. Process of dimensioning grid tariff components

The dimensioning of grid tariffs should be cost-reflexive yet cost adequate for the grid operator. Following this, we propose a pricing principle based on [15] which combines the average price principle used in German regulation with a *cost driver analysis* by applying the average price principle using specific grid costs (often referred to the term grid postage stamp in Germany) to three main categories of grid cost drivers: structure-related costs $k_{grid}^{structure}$, capacity-related costs $k_{grid}^{capacity}$, and energy-related costs k_{grid}^{energy}.

For this, we first have to define a *cost basis* K_{grid}^{base} for the distribution grid in the market region by simulating the *BAU scenario* in which average current grid tariffs for customers are implemented in the market region. The sum of the individual costs defines the total revenues of the DSO. Assuming that the DSO operates efficiently and the average grid tariffs are cost adequate, the current cost basis of the distribution grid is obtained.

In a second step, this cost base is divided into the three categories of cost drivers. The relation between K_{grid}^{base} and the total grid costs related to the described cost drivers $K_{grid}^{structure}$, $K_{grid}^{capacity}$ and K_{grid}^{energy} is given by:

$$K_{grid}^{structure} = \alpha K_{grid}^{base}, \tag{15}$$

$$K_{grid}^{capacity} = \beta K_{grid}^{base}, \tag{16}$$

$$K_{grid}^{energy} = \gamma K_{grid}^{base}, \tag{17}$$

where α, β and γ are values of percentage which add up to 100 % and can be estimated by carrying out a cost driver analysis for the grid region. In the context of this work, we applied results from existing cost driver analyses in literature [16], [15], [17] to our cost basis. According to literature, approx. 70 % of the total costs induced by a distribution grid customer are related to structural parameters of the grid, while a rough estimation of 2.5 % of the costs are energy dependent grid losses, i.e. energy-related costs [15]. Consistent with [17] the left over 27.5 % are assumed to be capacity-related costs. It shall be noted, that in this work the highly time and location dependent energy-related costs connected to congestion measures as well as the distinction between long-term installed capacity related costs and collective peak load related costs within the capacity-related costs are neglected [15]. We further define consumption-related costs $K_{grid}^{consumption}$ as the sum of capacity- and energy-related costs $K_{grid}^{capacity}$ and K_{grid}^{energy} as these are grid costs which the customer can affect by changing their consumption.

After the definition of the cost bases per cost driver $K_{grid}^{structure}$, $K_{grid}^{capacity}$, K_{grid}^{energy} and $K_{grid}^{consumption}$, we can define the *specific grid costs* $k_{grid}^{structure}$ in Euro per year, $k_{grid}^{capacity}$ in Euro per kilowatt and k_{grid}^{energy} in Eurocent per kilowatt-hour as well as the specific grid costs of consumption $k_{grid}^{consumption}$ in Eurocent per kilowatt-hour using the average price principle. In this context, we define

- $k_{grid}^{structure}$ as average grid costs each customer induced to the grid independent of their consumption,
- $k_{grid}^{capacity}$ as the average grid costs induced by one kilowatt consumption during the peak load in the distribution grid,
- k_{grid}^{energy} as the average grid costs induced by one kilowatt-hour of energy withdrawal and
- $k_{grid}^{consumption}$ as the average costs that are induced to the grid by consumption levelized to the total amount of consumption in kilowatt-hour.

In line with these definitions, we can calculate the specific grid costs as follows:

$$k_{grid}^{structure} = \frac{K_{grid}^{structur}}{N_{customer}} \tag{18}$$

$$k_{grid}^{capacity} = \frac{K_{grid}^{capacity}}{P_{max,tot,D}^{BU}} \tag{19}$$

$$k_{grid}^{energy} = \frac{K_{grid}^{energy} \cdot 100 \frac{ct}{\text{Euro}}}{\sum_{t=1}^{8760} \sum_{i \in I} \sum_{m \in M} E_{i,t}^{m,buy}} \tag{20}$$

$$k_{grid}^{consumption} = \frac{K_{grid}^{consumption} \cdot 100 \frac{ct}{\text{Euro}}}{\sum_{t=1}^{8760} \sum_{i \in I} \sum_{m \in M} E_{i,t}^{m,buy}} \tag{21}$$

where $N_{customer}$ is the number of customers in the distribution grid. The dispatch values $E_{i,t}^{m,buy}$ as well as the aggregated peak load $P_{max,tot,D}^{BU}$ are obtained from the *scenario without grid tariffs*. That is to remove the effect of incentivized flexibility usage by any type of grid fee on the specific cost determination.

In the next step, alternative grid tariff components can be determined using the specific grid costs. Here we seek for a cost-reflective connection between the grid fee and the grid costs. Therefore, the specific capacity costs $k_{grid}^{capacity}$ shall be priced by either a CPP or a backup capacity fee. To keep cost adequacy, we define:

$$fee^{CPP} = k_{grid}^{capacity}, \tag{22}$$

$$fee^{BU\text{-}capacity} = k_{grid}^{capacity} \cdot \frac{P_{max,tot,D}^{BU}}{\sum_{i \in I} P_{max,i}^{BU}}. \tag{23}$$

Equivalently, we define a fixed grid fee fee^{fix} and a conventional static energy fee fee_{static}^{energy} as follows:

$$fee^{fix} = k_{grid}^{structure}, \tag{24}$$

$$fee_{static}^{energy} = k_{grid}^{energy}. \tag{25}$$

Since time-varying energy fees fee_t^{energy} per time step t are designed to not only set a price for energy consumption but also to shift consumption they affect both energy-related and capacity-related cost drivers. Therefore, the time-varying energy fees are dimensioned using the previously defined specific grid costs of consumption $k_{grid}^{consumption}$. We construct a fee that shall increase during periods high load and decreases in periods of low or even negative load during generation surplus while leading to an average cost per Kilowatthour of $k_{grid}^{consumption}$ for the consumer. Therefore, we connect the value of the energy fee with the residual load at the hv-mv-transformer (from now on referred to as "residuum"). The relationship between the residuum and the energy fee is shown schematically in Fig. 3.

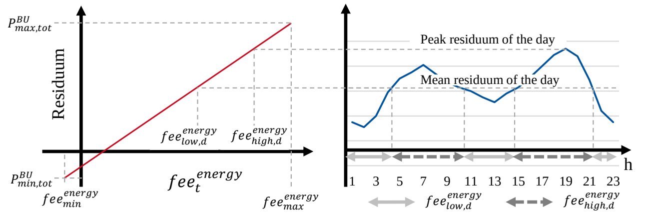


Fig. 3. Relationship between the time-varying energy fee and the residuum

TABLE I
GRID TARIFFS IN DIFFERENT SCENARIOS

Scenario		BAU		TVE	CPP	BCP
User type		res.	com.	all	all	all
fix fee	€/a	57	-	354	354	354
static energy fee	ct/kWh	5.33	5.18	-	0.13	0.13
dyn. energy fee	ct/kWh	-	-	∅1.52	-	-
capacity fee	€/kW	-	11.68	-	-	-
CPP	€/kW	-	-	-	50.35	-
BU-capacity fee	€/kW	-	-	-	-	7.89

Each day is divided into a high price period and a low price period based on the mean residuum of the day to reduce unnecessary load shift and increase transparency for the consumer. Time steps with a residuum lower than the mean residuum is given the low price $fee^{energy}_{low,d}$ and time steps with a residuum higher or equal to the mean residuum the high price $fee^{energy}_{high,d}$. The prices of the high price periods and the low price periods are set by the maximum absolute resdiuum of all high price periods or, respectively, low price periods of that day. For that, we define a linear relationship between the residuum of the whole simulation period and the energy fee. Thus, the maximum value of the energy fee fee^{energy}_{max} is set for the period with the maximum residuum $P^{BU}_{max,tot}$, the lowest value fee^{energy}_{min} correspondingly for the minimum residuum $P^{BU}_{min,tot}$. The price spread Δfee^{energy} between the two values can be set independently to increase or decrease the incentive of the fee to shift flexible load. In this work, Δfee^{energy} is set to the following:

$$\Delta fee^{energy} = fee^{energy}_{max} - fee^{energy}_{min} = 2 \cdot k^{consumption}_{grid}. \tag{26}$$

In the last step, we define cost adequate grid tariffs from a set of alternative grid tariff components. We differentiate between capacity-based grid tariffs that include either a CPP or a backup capacity fee and dynamic energy-based grid tariffs that include a time-varying energy fee. Besides that all tariffs include the fixed component fee^{fix}. Capacity-based grid tariffs additionally include the small static energy fee fee^{energy}_{static} for the energy-related grid costs.

IV. CASE STUDY

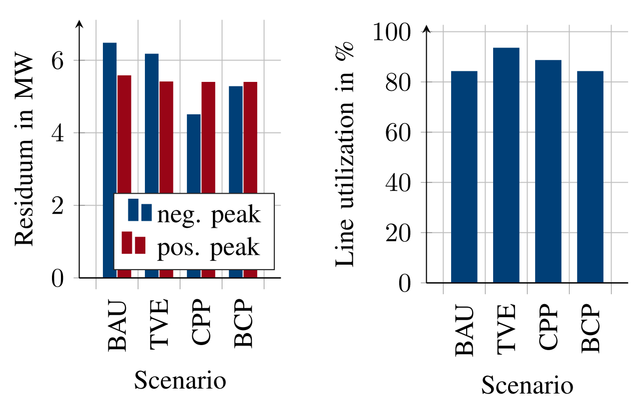
A. Scenario description

The study area is a synthetically generated distribution grid area in southern Germany [18]. It consists of a total of 3031 customer connections divided between 2654 residential and 377 commercial customers. Supply structure is based on [3]. Price assumptions are taken from the average electricity price for consumers in Germany 2021 as well as feed-in tariffs for PV power plants based on the assumed year of construction.

We analyze a BAU scenario with the current grid tariffs for residential (res.) and commercial (com.) users, as well as alternative scenarios *time-varying energy fee (TVE)*, *CPP*, and *backup capacity fee (BCP)* using the alternative grid tariff components. The assumed tariffs for the BAU and the determined grid tariffs for the alternative scenarios can be found in Table I.

B. Effects of dynamic grid tariffs on grid operation

Fig. 4a shows the effect of the alternative grid tariffs on the peak positive (generation exceeds load) and negative (load exceeds generation) residuum and Fig. 4b shows the peak line utilization in the grid. All alternative grid tariffs can reduce the peak negative residuum compared to the BAU-scenario by $4.7 - 30.5\,\%$ with the CPP being the most effective. The positive residuum can be reduced by $3.1 - 3.3\,\%$. This relief of the hv-mv transformer can not be observed for the maximum line utilization. With a CPP, the maximum line utilization increases by $4.4\,\%$-points and with the dynamic energy fee by $9.3\,\%$-points meaning a higher chance of line congestion. Only the backup-CP does not increase the maximum line utilization. In the TVE and the CPP scenarios the marginal costs for consumption from the public grid only increases during periods with high expected aggregated load. In periods with low expected aggregated load, consumption from the public grid is even incentivized compared to the BAU scenario due to lower consumption-dependent grid fees. This leads to higher consumption via the public grid and thus can locally result in higher line utilization. In the BCP scenario the heterogeneity of individual peak loads reduces this effect due to less simultaneity of consumption from the public grid.



(a) Peak hv-mv-residuum (b) Peak line utilization

Fig. 4. Grid operation results for alternative grid tariff scenarios

C. Effects of dynamic grid tariffs on market participants

Fig. 5 depicts the average income minus expenses of different categories of LEM participants from total electricity sales and purchases including grid fees on both LEM and backup utility for all scenarios. The results show that with the backup-CP tariff participants with a flexible consumption unit can reduce their average electricity costs by $21.3\,\%$ while for participants without flexible consumption their costs increase by $109.5\,\%$. This cost redistribution is reduced but not diminished with a CPP. The main reason for that is that flexible participants can shift consumption away from peak load periods while inflexible participants decrease their backup consumption during peak load periods by purchasing more expensive energy on the LEM. Since the consumers can only forecast their load one day in advance, there are many more time periods with anticipated peak loads leading to increased LEM prices than the one time step with the annual peak load for which the capacity fee actually has to be paid.

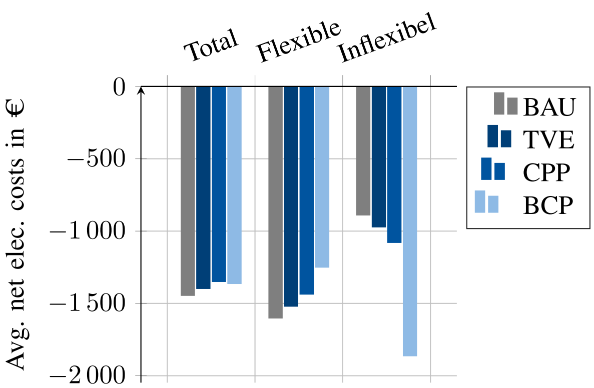


Fig. 5. Cost distribution of market participants in different scenarios

This effect on the LEM prices can be also seen in Fig. 6 where the average costs per kilowatt-hour electricity purchased on the LEM and from the backup are compared. While in the BAU and the TVE scenarios consumers only buy electricty on the LEM if the prices are lower than from the backup, consumers with a CPP or a backup-CP tariff are willing to pay much higher prices on the LEM if they expect to save capacity fees with it leading to average prices on the LEM higher than the electricity costs from the backup. The higher price increase in the BCP scenario compared to the CPP scenario can be explained by the heterogeneity of load peaks of consumers. While with the CPP all consumers face increased grid fees during the same time step and LEM trade is therefore limited to residual generation of prosumers, with a backup-CP prosumers are willing to sell generation normally used for self-consumption for high prices as long as they do not anticipate peak load times themselves.

With a dynamic energy fee minor cost redistribution effect can be observed from flexible to inflexible participants as well. Here, the increased costs of inflexible participants can be explained by the increased fix component of the grid tariff which redistributes costs from participants with high consumption, i.e. typically with flexible heat pumps or electric vehicles, to participants with low consumption. In total among all participants the alternative grid tariffs lead to decreased yearly electricity costs by $3.7\,\%$ (dynamic energy fee) to $8.6\,\%$ (CPP) due to decreased grid fee payments from flexibility usage.

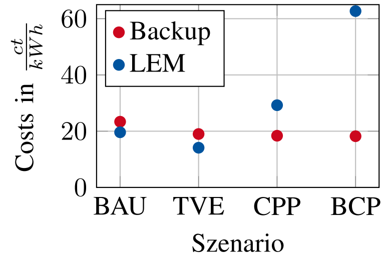


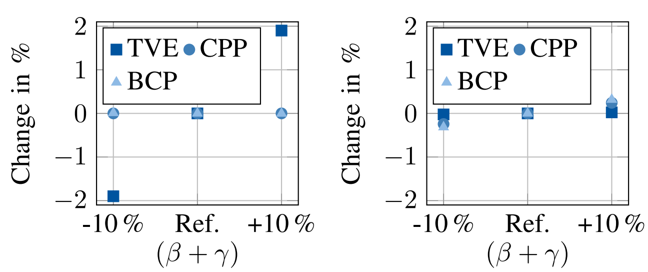
Fig. 6. Weighted average electricity costs per kilowatt-hour on the LEM and from the backup over one year without fix or capacity components

D. Sensitivity of results on uncertainty in grid cost drivers

In order to determine the impact of uncertainty in the cost driver analysis, we analyse alternative distributions of grid costs to the cost drivers. For this, we alter the parameters $(\beta + \gamma)$ from (15)-(17) by $\pm 10\,\%$ resulting in an equivalent increase/decrease of the (average) energy fees, capacity fees as well as the price spread Δfee^{energy} for time-varying energy fees and - due to a constant K^{base}_{grid} - a corresponding decrease/increase of the fix grid tariff component. The results for the peak hv-mv-residuum and the total social welfare as defined in (1) are shown in Fig. 7a and Fig. 7b.

The results for the CPP and BCP scenarios indicate that the grid-serving use of flexibility is saturated during peak residuums for capacity fees in that magnitude. Since the grid tariff costs shift from fix costs to consumption-dependent costs with increasing $(\beta + \gamma)$ the same use of flexibility results in higher grid tariff cost savings and thus leads to a slight increase in social welfare to the detriment of the grid operator who receives less income from grid tariffs.

In the TVE scenarios the increase of $(\beta + \gamma)$ has a negative effect on the reduction of the peak residuum. This can be explained by the sub-optimal load shifting incentive during periods where the grid residuum was not critical leading to a new peak residuum during a low price period. Due to the more flat-rate nature of the energy fee no impact on the social welfare was determined in this sensitivity analysis.



(a) Peak hv-mv-residuum (b) Social welfare

Fig. 7. Sensitivity of (a) peak hv-mv-residuum and (b) social welfare on change in grid tariff distribution

V. Discussion

In this study, we have discussed the topic of grid-serving grid tariffs in LEMs. For this, we proposed a methodology for the design and dimensioning of both cost-adequate and cost-reflective grid tariffs with either a time-varying energy-based grid fee or a capacity-based grid tariff components. This methodology has been implemented in an exemplary study with a single synthetically generated grid region. Thus, general conclusions can not be given without extending the analysis to a variety of typical grid regions with specific data to cost drivers.

The exemplary study indicates that all proposed alternative grid components can decrease the peak load extracted from the transmission grid. The magnitudes of peak reduction of around 5 % with time-varying energy fees and around 30 % with capacity fees is similar the results found in [2] and [9]. However, the alternative grid tariffs may also increase line utilization within the distribution grid leading to higher costs for congestion measurements. For an economic efficient conclusion to this trade-off a cost analysis for the grid region would need to be included within the evaluation of the grid tariff. Additionally, alternative grid tariff schemes that include local grid variables like the line utilization could be implemented but require more detailed information of distribution grid operation.

The results further indicate a high redistribution of welfare if alternative capacity-based grid tariffs are implemented. The redistribution from base loads to flexible loads with a capacity fee similar to the CPP is also found in [9]. This may lead to a lower acceptance for these grid tariffs. A major reason for the high redistribution is the unpredictability of future peak loads and the inefficiently high amount of load shifting leading to increased prices on the LEM. This effect could be reduced by decreasing capacity-based fees significantly. A fee in the magnitude of cents per kilowatt may give a similar outcome in the amount of load shifting while reducing the effect on the LEM price.

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