IMPACT OF NETWORK CHARGE MECHANISMS ON CONSUMERS, PROSUMERS, AND THE ENERGY SYSTEM

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Overview

The transformation of our energy system toward zero net CO_2 emissions correlates with a stronger use of low-energy density renewable energy sources (RES). This involves numerous distributed stakeholders, who evolve from passive energy consumers to active market participants (prosumers). Distributed photovoltaic (PV) power systems, in combination with controllable flexibility elements such as battery storage systems, are expected to play a major role in this evolution. In principle, prosumer storage capacities can provide necessary sources of system flexibility. However, prosumer battery systems oftentimes operate for individual profit maximization, only.[2] In principle, three prototypical battery operation modes can be distinguished as follows:

a) Batteries can operate for individual profit maximization of the local operator, depending on the regulatory framework. This often equals self-consumption maximization; scope of analysis: n = one household.

b) Batteries can operate (distribution) network-beneficially, reducing peak-coincident network utilization; scope of analysis: n = tens to hundreds of households.

c) Batteries can operate market-beneficially to leverage portfolio effects for optimal renewable energy integration at the wholesale market (system) level; scope of analysis: n = thousands to millions of households.

Moreover, smoothing effects arise at both the distribution network and wholesale market levels, affecting the actual impact of prosumer behavior on the energy system [2]. In turn, prosumer behavior is strongly driven by the specific regulatory framework in place. For frameworks with volumetric network charges, profit maximization often results in self-consumption maximization [1]. However, from a system perspective, self-consumption maximization by means of predetermined prosumer heuristics results in overall flexibility reduction, potentially burdening both the distribution network and the wholesale market; see [3], for instance. Alternative network cost allocation schemes could provide incentives for different battery operation modes, leading to different household energy bills, different utilizations of the distribution network, and, ultimately, different system costs. Based on the work of [4], this study provides a novelty value in quantifying these effects, thus presenting a fully consistent overview of individual, local, and global effects of prosumers facing different network charge mechanisms.

Methods

This study's approach involves establishing a closed-loop analysis of prosumer battery operation and an analysis of the resulting full costs of electricity (FCOE). Additionally, the process includes an analysis of network capacity utilization and a study of the resulting total system costs. These are examined using a fundamental linear optimization model for the three flexibility operation modes (denoted by 1, 2, 3 and further defined in the following sections; see Figure 1). For the FCOE analysis, the study applies realistic quarter-hour household profiles (in contrast to synthetic, and already aggregated, "H0 profiles") for electric demand and PV production. The FCOE contain the levelized cost of energy (LCOE: annualized fixed and variable costs of energy) and regulatory network charges under consideration of two different allocation schemes:

- A: Volumetric network costs
- B: Peak-coincident capacity charges; as detailed by [5], for instance

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[2] This is true at least in regulatory frameworks comparable to the German one, with predominantly volumetric taxes and levies; see [1], for instance.

Both prosumer and consumer (residual) load profiles are aggregated at the distribution network level under consideration of simultaneity effects. The resulting aggregated residual load profiles per distribution network node are quantified to measure the distribution network (thermal) stress level that is induced through different prosumer behaviors (i.e., different battery operation modes).

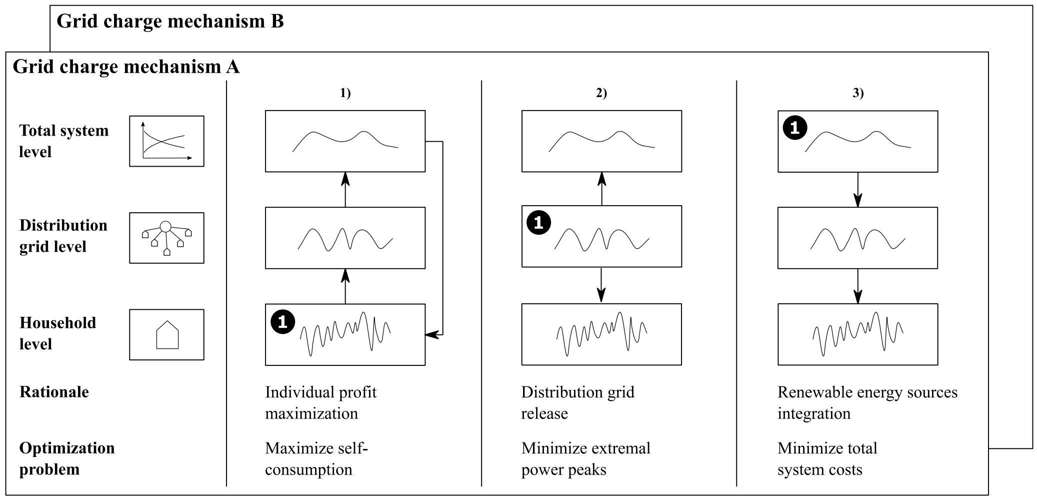


Figure 1: Workflow of analysis; circled “1” denotes technical starting point of analysis (first step in model chain), corresponding to the respective battery operation mode (1, 2, or 3).

Finally, the residual load profiles are further smoothed to generate aggregated wholesale market profiles. These residual load profiles enter a linear optimization model of the electricity market, which minimizes the total system costs. Each battery operation mode leads to a different residual load profile at the wholesale market level and thus to a different system optimum.

A. Battery Operation Mode 1: Maximization of prosumer self-consumption

Battery operation

The rationale behind Battery Operation Mode 1 is to maximize prosumer self-consumption. Generally, there are multiple possible algorithms that can accomplish this objective. In this manuscript, an algorithm is used that is referred to as “chronological charging”; see [4]. This algorithm promotes the use of self-produced electricity whenever possible, either directly for momentary consumption or indirectly for charging the prosumer battery. A pseudocode is provided in Algorithm 1, with variable and parameter descriptions provided by Table 1.

Table 1: Summary of used variables and parameters for prosumer battery storage operation

	Description	Unit	Value	Source
Variables				
fi	Prosumer feed-in of (surplus) PV production	[kW]	Output	-
gs	Prosumer grid load	[kWh]	Output	-
BattFillLevel	Fill level of battery	[kWh]	Output	-
Parameters				
ResLoad	Prosumer load—PV production	[kW]	Exogenous time series	[6]
TimeRes	Time resolution of modelling	[h]	0.25	Model parameter
BattPower	Battery discharging power	[kW]	3	Assumption
BattCharging	Battery charging power	[kW]	3	Assumption
BattContent	Maximum battery storage content	[kWh]	6	Assumption

```
For tn ∈ T = {ti = 0; ft = 35,040} do
    if ResLoad ≥ 0 then
        fi = 0
        if ResLoad ≤ BattPower then
            if BattFillLevel - ResLoad × TimeRes ≥ 0 then
                gs = 0
                BattFillLevel = BattFillLevel - ResLoad × TimeRes
            else
                gs = (ResLoad × TimeRes - BattFillLevel) / TimeRes
                BattFillLevel = 0
            end if
        else
            if BattFillLevel - BattPower × TimeRes ≥ 0 then
                gs = ResLoad - BattPower
                BattFillLevel = BattFillLevel - BattPower × TimeRes
            else
                gs = (ResLoad × TimeRes - BattFillLevel) / TimeRes
                BattFillLevel = 0
            end if
        end if
    else
        gs = 0
        if -ResLoad ≤ BattCharging then
            if BattFillLevel - ResLoad × TimeRes ≤ BattContent then
                fi = 0
                BattFillLevel = BattFillLevel - ResLoad × TimeRes
            else
                fi = (BattFillLevel - ResLoad × TimeRes - BattContent) / TimeRes
                BattFillLevel = BattContent
            end if
        else
            if BattFillLevel + BattCharging × TimeRes ≤ BattContent then
                fi = -ResLoad - BattCharging
                BattFillLevel = BattFillLevel + BattCharging × TimeRes
            else
                fi = (BattFillLevel - ResLoad × TimeRes - BattContent) / TimeRes
                BattFillLevel = BattContent
            end if
        end if
    end if
end for
```

Algorithm 1: Pseudocode of the chronological charging algorithm (Battery Operation Mode 1).

The outputs from this algorithm are time series for the prosumer grid supply, $gs(t_n)$, and feed-in, $fi(t_n)$, which can be consolidated in one time series, referred to as the prosumer residual load[3] and denoted by $RL(t_n)$, as shown in Equation 1:

$$RL(t_n) = gs(t_n) - fi(t_n) \tag{1}$$

[3] Throughout this paper, the notion residual load refers to the residual load *after* battery operation, to be distinguished from ResLoad = prosumer load - prosumer PV production.

Next, one can evaluate the prosumer and consumer FCOE. The FCOE contain the annualized PV and battery investment costs (for prosumers), the wholesale market costs, and network charges, as depicted in Equation 2.

$$FCOE = \underbrace{c_{inv} \cdot x_{inv}}_{investment\ costs} + \underbrace{\bar{\lambda} \cdot (GS - \mathrm{MVF} \cdot FI)}_{(wholesale)\ market\ costs} + \underbrace{f(\dots) \cdot c_{network}}_{network\ charges} \tag{2}$$

In this equation, c_{inv} represents the specific investment cost vector (including PV and battery investment costs; parameters are set as shown in [4]). Additionally, x_{inv} contains the respective installed PV and battery capacities (PV: 6 kW_p; battery: 6 kWh); $\bar{\lambda}$ represents the average (wholesale) market price and is assumed to be 150 EUR/MWh including CO_2 prices[4]; and *GS* and *FI* stand for the annual amounts of energy withdrawn from the grid (*GS*: annual grid supply; $GS = \sum gs(t_n)$) and fed into the grid, respectively (*FI*: annual feed-in; $FI = \sum fi(t_n)$). The market value factor MVF accounts for the actual PV wholesale market value and is assumed to be 50% in this study. The last term in Equation 2, $c_{network}$, represents the specific network costs (either per kWh in the volumetric case or per kW in the case of peak capacity charges). Elsewhere, *f(…)* is specified in the following chapter as either a function of the volume (volumetric network charges) withdrawn from the grid or the peak power withdrawn from or fed into the grid (peak capacity charges).

Network utilization and charges

Next, this study quantifies the resulting peak-coincident network capacity utilization—that is, the stress level induced at a distribution network node through the respective prosumer battery operation. In this analysis, this is performed using a stylized approach under a few assumptions and simplifications:

- Assumption of a radial distribution network topology;
- Consideration of thermal stress on components only, neglecting other aspects, such as voltage unbalance or the like; and
- Use of prototype (residual) load profiles.

To be precise, this study assumes *n* households to be connected to a network node, of which 25% are assumed to be traditional consumers, and 75% are assumed to be prosumers with PV and battery storage systems. To quantify the actual residual load on the network node, one must first smooth the sharp prosumer and consumer[5] household (residual) load profiles as described in the next paragraph, denoted by a circumflex in this paper, to account for simultaneity effects. Second, the smoothed prosumer and consumer profiles ($\widehat{RL}_{Pros}, \widehat{RL}_{Cons}$) are superposed according to their respective penetration ratios (ρ = 75% prosumers; 1 - ρ = 25% consumers), resulting in the actual network node residual load (RL_{Node}), as shown in Equation 3.

$$RL_{Node}(t) = \mathrm{n} \cdot \left(\rho \cdot \widehat{RL}(t)_{Pros} \cdot (1 - \rho) \cdot \widehat{RL}(t)_{Cons}\right) \tag{3}$$

The profile smoothing is performed using Gaussian smoothing.[6] It begins from a given (sharp) initial residual load profile and generates further residual load profiles by shifting the initial profile values to the left and right (in the temporal dimension). For the aggregation, shift probabilities are weighted by a Gaussian normal distribution, as shown in Equation 4.

$$\widehat{RL}(t_0) = \int_{-\infty}^{\infty} RL(t) \cdot \frac{1}{\sqrt{2\pi\sigma^2}} \cdot e^{-\frac{(t-t_0)^2}{2\sigma^2}} dt \tag{4}$$

Applying $\sigma = \sqrt{n}$, Figure 2 demonstrates that this approach is indeed in asymptotical accordance with the theoretical functional $1/\sqrt{n}$ dependency, as originally derived by [7]; see Equation 5.

$$g(n) = \mathrm{g}_\infty + (1 - \mathrm{g}_\infty) \cdot \frac{1}{\sqrt{n}} \tag{5}$$

[4] It is chosen to be high enough to enable prosumers to re-finance their investments into PV entirely through the market price. In general, λ follows as dual variable of the load coverage restriction as model-endogenous output. However, in this study, to isolate the effects of different network charge schemes, it is set to a fixed value throughout the paper.

[5] Consumer residual load (RL_{Cons}) = consumer load

[6] Aso referred to as Gaussian blurr in other fields such as image processing.

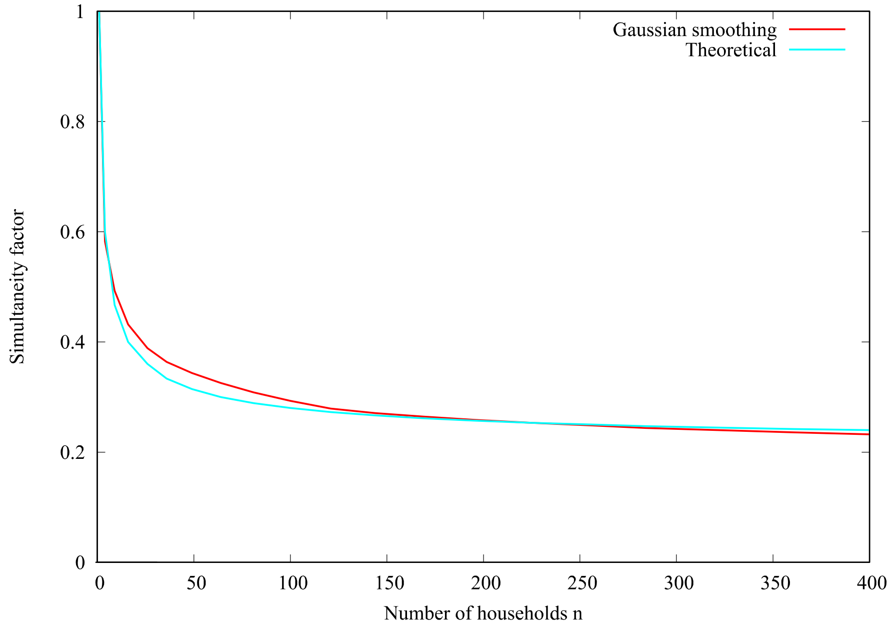


Figure 2: Simultaneity factor resulting from Gaussian smoothing versus theoretical simultaneity factor (g_∞ = 0.20).

In this equation, g represents the simultaneity factor, which is defined as the ratio of the maximum of n aggregated time series versus the sum of n maxima of the initial time series. Throughout the paper, $\sigma = 7$ is used for smoothing at the distribution network level. The network charges are now derived as follows:

- For volumetric network costs (*VNC*): $VNC = GS \cdot \mathrm{c}_{\mathrm{network}}^{\mathrm{vol}}$
- For peak-coincident capacity charges (*PCC*): $PCC = \overline{RL^{peak}} \cdot \mathrm{c}_{\mathrm{network}}^{\mathrm{peak}} + C_{network}^{per\ customer}$

The realization of peak-coincident capacity charges is loosely informed by [5]. The peak capacity charges are complemented by an additional fixed charge per customer. This is due to the fact that a network cost refinancing which is purely based on peak-coincident capacity charges could necessitate excessively high network charges. Table 2 provides the description and setting of the input parameters for the network charge formulations.

Table 2: Summary of variables and parameters for the network charge mechanisms

	Description	**Unit**	**Value**
Variables			
$\overline{RL^{peak}}$	Prosumer/consumer residual load as average over top 30 residual power peaks at distribution grid node	[kW]	Model output
$C_{network}^{per\ customer}$	Per capita network charges compensating for the residuum between total network costs and refinancing carried out through capacity charges	[EUR/p.c.]	Model output
Parameters			
$\mathrm{c}_{\mathrm{network}}^{\mathrm{vol}}$	Specific volumetric network charges	[EUR/MWh]	50
$\mathrm{c}_{\mathrm{network}}^{\mathrm{peak}}$	Specific network capacity charges	[EUR/kW]	100

System analysis

This study determines the total system (wholesale market) costs by using a fundamental linear optimization model of the European electricity market, the *European Electricity Market Model*, *E2M2*; see [8] for a detailed overview. In [4], there is a detailed description of the model structure and parameter settings which are used in this paper, including the cost vector c^T and the decision variable vector x. Next, the residual load as an aggregation of all prosumer and consumer households enters the system model, as (from a systemic perspective) an exogenous time series. Subsequently, the annualized total system costs are minimized, as shown in Equation 6.

$$\min_{x \in \mathbb{R}_+^n} C_{sys}^{total} = \min_{x \in \mathbb{R}_+^n} c^T \cdot x \tag{6}$$

For the profile aggregation at system level, the study applies the same methodology, Gaussian smoothing, as detailed in the last section. This paper uses $\sigma = 20$ for smoothing at the wholesale market level. The system model realistically depicts several constraints as characteristic features of the electricity market. The most important of these are load coverage, system adequacy, and the depiction of RES investment paths. A detailed discussion of these features is shown in [4]. The number of households (40 million) and the annual electricity demand (500 TWh) are loosely informed by the German market size. The power plant structure is dominated by RES: 180 GW PV, 60 GW wind offshore, and 100 GW wind onshore, loosely based on the 2050 values of a 95% decarbonization scenario.

B. Battery Operation Mode 2: Reduction of peak-coincident network utilization

The principal analysis steps for Operation Mode 2 are the same as presented above for Operation Mode 1. However, this time the actual battery operation mode is adjusted to reduce the peak-coincident network utilization. At this point, the battery operation is formulated as a linear optimization problem, with the prosumer self-consumption as an objective function being maximized, as shown in Equation 7.

$$SC = D_{Pros} - \sum_t gs(t) \rightarrow \max \tag{7}$$

For the model, the technical characteristics of the battery (battery charging and power, battery content, etc.) are represented as linear restrictions, congruent to the formulation in Algorithm 1, as shown in Algorithm 2.

Set $0 \leq \text{UpperBound}_i < \text{UpperBound}_{i-1}$ such that linear optimization problem is (still) solvable

Try

Objective function

$SC = \mathrm{D_{Pros}} - \sum_t gs(t) \rightarrow \max$

Restrictions

Load coverage

$\mathrm{d_{Pros}(t_n)} = \mathrm{p_{PV}(t_n)} + p_{Batt}(t_n) - s_{Batt}(t_n) + gs(t_n) - fi(t_n) \quad \forall\, t_n \in T$

Capacity (power) constraints

$\mathrm{p_{PV}(t_n)} = \mathrm{FLH} \cdot \mathrm{Profile}(t_n) \cdot \mathrm{P_{PV,\,peak}} \cdot \frac{1}{\mathrm{TimeRes}} \quad \forall\, t_n \in T$

$p_{Batt}(t_n) \leq \mathrm{BattPower} \quad \forall\, t_n \in T$

Storage constraints

$s_{Batt}(t_n) \leq \mathrm{BattCharging} \quad \forall\, t_n \in T$

$BattFillLevel(t_{n+1}) = BattFillLevel(t_n) + (s_{Batt}(t_n) \cdot \eta_s - p_{Batt}(\mathrm{t_n}) \cdot \eta_p) \cdot \mathrm{TimeRes} \quad \forall\, t_n \in T$

$0 \leq BattFillLevel(t_n) \leq \mathrm{BattContent} \quad \forall\, t_n \in T$

Peak capacity restrictions for aggregated residual load at node

$gs(t_n) \cdot \rho + \mathrm{d_{Cons}(t_n)} \cdot (1 - \rho) \leq \mathrm{UpperBound_i} \quad \forall\, t_n \in T$

$fi(t_n) \cdot \rho \leq \mathrm{UpperBound_{\,i}} \quad \forall\, t_n \in T$

End if $|\text{UpperBound}_i - \text{UpperBound}_{i-1}| < \varepsilon$

Algorithm 2: Pseudocode of algorithm to determine Battery Operation Mode 2.

Notation—$\mathrm{D_{pros}}$: annual electricity demand of prosumer household; $\mathrm{d_{pros}(t_n)}$: momentary prosumer electricity demand; $\mathrm{p_{PV}(t_n)}$: momentary PV production; $p_{Batt}(t_n)$: momentary power supply from battery;

$s_{Batt}(t_n)$: momentary battery charging; FLH: (PV) full load hours (= 1,050h in this study); $P_{PV,\,peak}$: Peak PV capacity; η_s: battery charging efficiency (= 1 in this study); and η_p: battery dis-charging efficiency (= 1 in this study).

At this point, one determines the lowest value possible for an upper boundary that restricts the residual load at the distribution network node while still leaving the optimization problem solvable. This upper bound can be found using interval nesting. In turn, the corresponding resulting prosumer residual load serves as input for the subsequent analyses of network utilization and system costs, as described in detail for Operation Mode 1.

C. Battery Operation Mode 3: Minimization of total system costs

Next, Operation Mode 3 differs from the other operation modes in that this time, the prosumer battery serves as a full flexibility option on the wholesale market. For Operation Modes 1 and 2 we determined the aggregated residual load of the prosumer and consumer households as system model-exogenous time series. For Operation Mode 3, instead, we being the analysis with the minimization of total system costs, leaving the battery operation as a degree of freedom for the system. In this way, the battery operation and the corresponding prosumer residual load are endogenous results of the system optimization. Next, the distribution network capacity utilization is determined in a similar way to that described in the preceding subchapters. To do so, one must make the prosumer and consumer residual profiles sharper, going from the wholesale market level to the distribution network level to produce consistent (and hence comparable) results with Operation Modes 1 and 2. This is done by applying Equation 4. Finally, the prosumer and consumer FCOE are revealed.

Results

A. Global perspective: System effects

As illustrated by Figure 3, the total system costs are highest for Operation mode 1 (chronological charging of battery) and lowest for operation mode 3 (market-beneficial battery operation). The relative system cost delta is 0.5%, corresponding to ca. 230 MN EUR p.a. with a system cost base of roughly 50 BN EUR p.a. This system cost effect is based on the fact that a flexible battery operation (as in Operation Mode 3) enables an overall better RES integration than in the case of a pre-determined battery operation as in Operation Mode 1. This fact leads to overall lower fuel and CO_2 costs in the system. For a more detailed discussion, one may read [4].

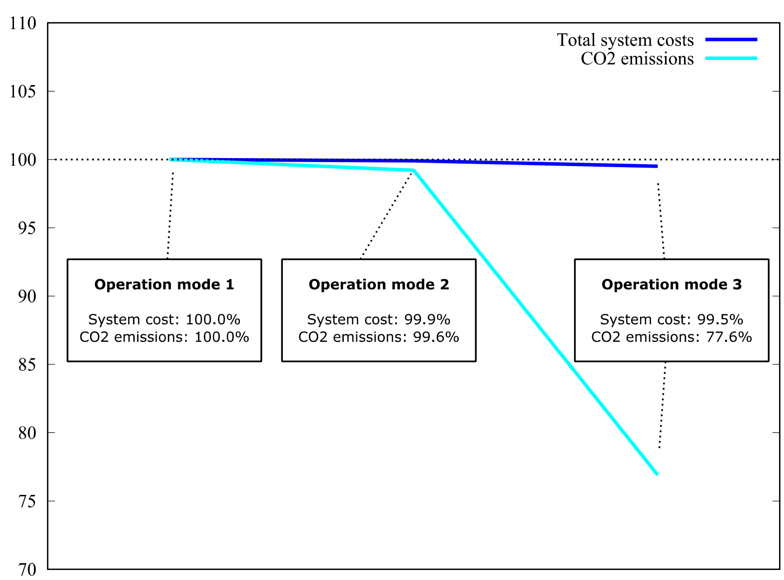
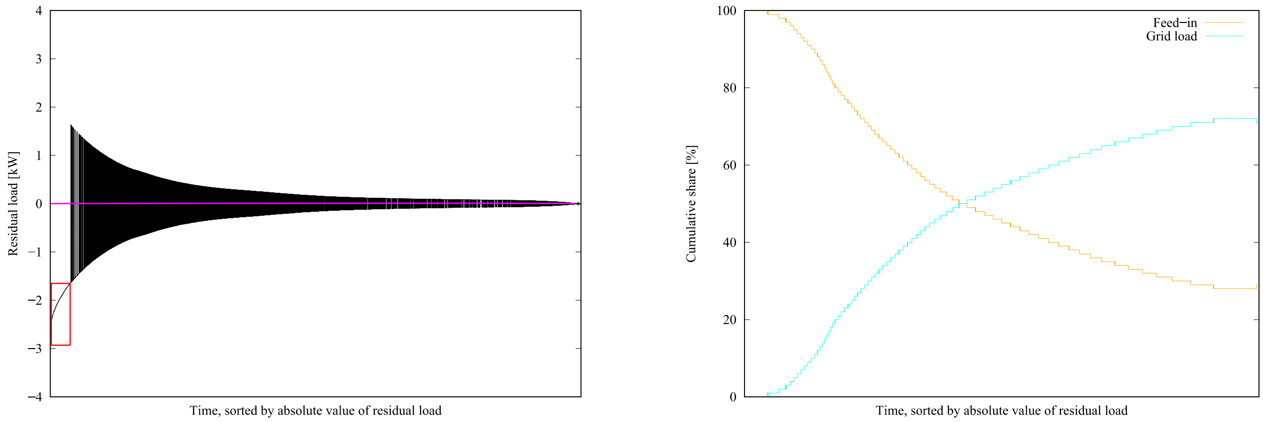


Figure 3: Annualized total system costs and CO_2 emissions, normalized in % of respective values for battery Operation Mode 1, by battery operation mode.

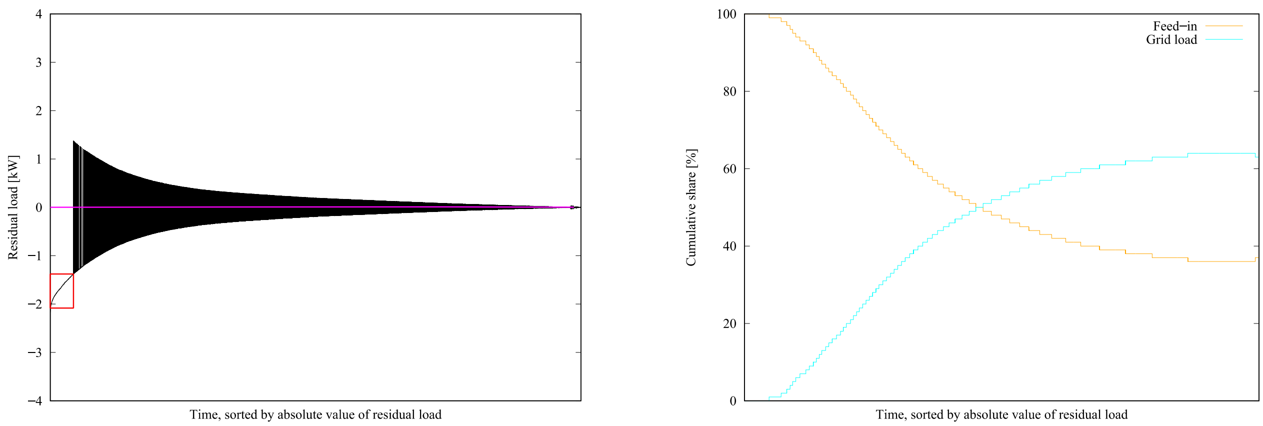
Interestingly, also Battery Operation Mode 2 leads to a system cost advantage, albeit a small one (0.1%), compared to Battery Operation Mode 1. This is not a self-evident result in that the rationale behind Battery Operation Mode 2 is to release stress on the distribution grid, which is not per se congruent to a market-beneficial battery operation. In fact, this result cannot directly be generalized, so a parameter variation analysis should be conducted to test the stability of the results, which is left open for a subsequent paper. Additionally, the different battery operation modes show even stronger differences in their CO_2 emissions. The underlying cause is the same as that of the total system cost decrease: better overall RES integration, especially in Operation Mode 3, leading to a reduction of the unit commitment of dispatchable, CO_2-intensive power plants (gas turbines). In case that the overall greenhouse gas (GHG) emissions are limited by a fixed Emissions Trading System (ETS) cap, there would not be an overall CO_2 emissions difference between the three battery operation modes. Instead, Battery Operation Mode 3 could achieve the same CO_2 targets with less overall RES capacity installed compared to Operation Modes 1 and 2.

B. Local perspective: Network utilization

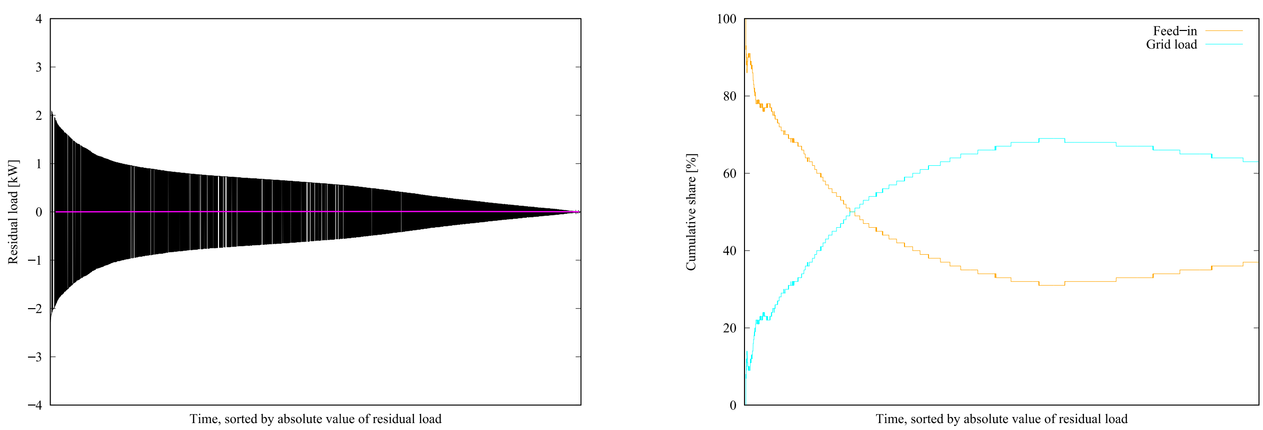
To evaluate the effects at the distribution network level, this study quantifies the residual loads on the distribution network node for each of the battery operation modes 1, 2, and 3; see Figure 4.



(a) Operation Mode 1



(b) Operation Mode 2



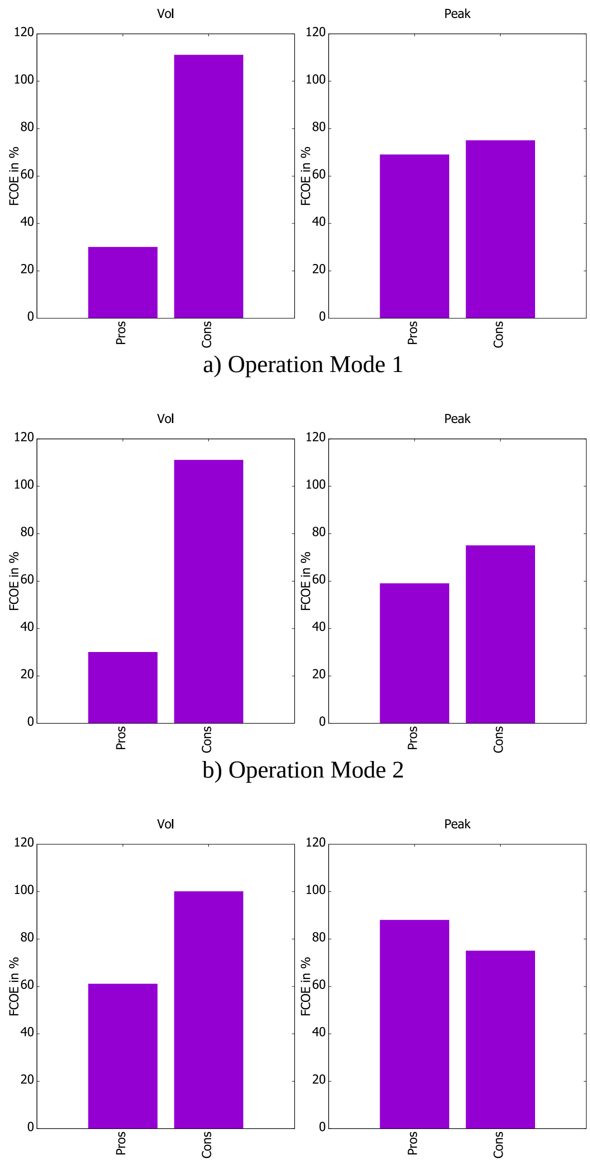
(c) Operation Mode 3

Figure 4: Annual residual load duration curves (absolute values, left side); cumulative shares of feed-in and grid load in the residual load (right side); by battery operation mode.

In the figure, the corresponding residual loads are evaluated for each time step of the model year and sorted by their magnitude (left side of Figure 4). On the right side of Figure 4, the representation depicts how much these residual loads are driven by demand peaks (in cyan) and by feed-in peaks (in orange), respectively. The intersections of these curves represent the points in (reordered) time up to which feed-in peaks and demand peaks have equally stressed the network. The maximum residual load peaks are highest for Battery Operation Mode 1 (2.9 kW per household), followed by Battery Operation mode 3 (2.3 kW per household). As expected, the lowest stress level for the distribution network node is achieved for the network-beneficial Operation Mode 2 (2.2 kW per household). In contrast to the market-beneficial Operation Mode 3, the highest residual load peaks for Operation Modes 1 and 2 are purely induced by the prosumer feed-in at the beginning (shown as red rectangles in Figure 4). Additionally, the different roles of feed-in peaks versus demand peaks in the different battery operation modes are shown in the right side of Figure 4, namely the different intersections of the feed-in and grid load curves. Thus, one can see clearly that the distribution networks are stressed predominantly by prosumer feed-in for all three battery operation modes. This is also true for Operation Mode 3, but to a lower extent.

C. Individual perspective: End customer effects

The analysis of prosumer (Pros) and consumer (Cons) FCOE helps identify which battery operation mode is favorable to prosumers, distinguishing two different network cost allocation schemes. Figure 5 depicts the normalized prosumer and consumer FCOE (normalization base: 800 EUR p.a.) for the three battery operation modes.



a) Operation Mode 1

b) Operation Mode 2

c) Operation Mode 3

Figure 5: FCOE for prosumers (Pros) and consumers (Cons), in % and normalized to 800 EUR/a, by network cost allocation scheme (Vol: volumetric network charges; Peak: peak-coincident capacity charges); by battery operation mode.

On the left side of the figure, the FCOE are evaluated for volumetric network charges. On the right side of the figure, the FCOE are evaluated for peak capacity charges. The figure depicts a couple of interesting results: First, investments in distributed PV and battery systems are economically viable both under volumetric and peak capacity network charges, in principle. This is generally true for all battery operating modes with the exception of Operating Mode 3 in combination with peak capacity charges. Second, one can clearly see that peak capacity charges generally tend to reduce the FCOE gap between prosumers and consumers (and even reverse it for Operation Mode 3). This is the case because volumetric network charges enable prosumers to more strongly reduce their shares of refinancing grid infrastructure and operation costs through self-consumption. This result is in line with other studies which have analyzed cross subsidies from consumers to prosumers in detail; see [9] and [10], for instance. However, this option is taken away in case of peak capacity charges. Third, one can see that from a prosumer perspective, the market-beneficial battery operation (Operation Mode 3) is neither favorable for volumetric nor peak capacity network charges. This demonstrates that further adjustments of the regulatory framework are needed to incentivize market-beneficial battery operation. As a consistency check, one can see that for peak capacity charges, the network-beneficial battery (Operation Mode 2) is favorable to the prosumer. Elsewhere, for volumetric network charges, chronological charging of the battery (Operation Mode 1) is favorable.

Conclusions

Overall, this manuscript evaluates the impact of prosumer behavior at the individual level (electricity bill), local level (distribution network stress), and the system level (total system costs). Volumetric network charges tend to favor battery operation modes that are neither grid- nor market-oriented. Such battery operation modes can lead to significantly higher thermal stress on the distribution network nodes. Additionally, these modes can cause overall higher system costs and CO_2 emissions because of reduced RES integration. Moreover, volumetric network charges can amplify the gap between prosumer and consumer household electricity bills. In contrast, peak capacity charges could constitute an incentive for different battery operation modes. These could reduce inequalities between prosumer and consumer electricity bills and simultaneously release the distribution network. However, it is unclear whether (and to what extent) a grid-oriented battery operation mode also results in corresponding positive market effects. In this study, market-oriented battery operation displays significantly better RES integration, resulting in overall lower system costs and CO_2 emissions. In a subsequent journal paper we will evaluate further aspects, first and foremost improvements to the prosumer heuristic presented in this paper that explicitly account for a prosumer response to a changed regulatory framework.

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