Modeling coordination between renewables and grid: Policies to mitigate distribution grid constraints using residential PV-battery systems

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ABSTRACT

Distributed photo-voltaic (PV) generation is one of the pillars of energy transitions around the world, but its deployment in the distribution grid requires costly reinforcements and expansions. Prosumage – consisting of a household-level PV unit coupled with a battery storage system – has been proposed as an effective means to facilitate the integration of renewable energy sources and reduce distribution grid stress. However, tapping its full potential requires regulatory interventions; otherwise, system costs could rise despite increasing flexibility. We analyze the effectiveness of different policy schemes to mitigate the need for distribution capacity expansion by incentivizing beneficial storage operation. Our novel top-down modeling approach allows analyzing effects on market prices, storage dispatch, induced distribution grid requirements, system costs, and distributional implications. Based on German power system data, numerical results indicate that distribution grid requirements can be reduced through simple feed-in policies. A uniform limit on maximum grid feed-in can leave distribution system operators better off, even if they fully compensate prosumage households for foregone revenue. Policies imposing more differentiated limits at the regional level result in only marginal efficiency improvements. Complete self-sufficiency (autarky) is socially undesirable, as it confines important balancing potential and can increase system costs despite adding storage.

1. Introduction

Distributed solar photo-voltaic (PV) generation is one of the pillars of the energy transition in Germany, Europe, and around the world. Its deployment at the distribution grid level poses new challenges to distribution system operators (DSOs), who are charged with the provision and operation of medium and low-voltage grids (Pudjianto et al., 2013). As regulated regional monopolies, DSOs are required to guarantee high quality and high reliability of services at all times. Thus, distribution grids are sized to handle even very rare peak events (Resch et al., 2017). Previously, dimensioning of distribution grids was driven by residential loads, where the probability of simultaneous peaks is low. By contrast, on a sunny day, all PV units in a region may generate close to their peak output simultaneously. Hence, the dimensioning of distribution grid infrastructure is now driven to an increasing degree by PV feed-in (Spiliotis et al., 2016). For Germany, studies have estimated additional investment requirements in the distribution grid of 23–49 billion EUR for the period 2015–2032 due to deployment of renewable energy sources (RES) (German Federal Ministry for Economic Affairs and Energy, 2014).

At the same time, decreasing battery storage costs (Schmidt et al., 2017) have led to the increased deployment of coupled PV battery systems (Kairies et al., 2016; Navigant Research, 2016). In Germany, such coupled systems will in many cases be more profitable than stand-alone PV installations from 2020 onwards (Dietrich and Weber, 2018). Extending the concept of electricity-producing and -consuming households (prosumers), we use the term prosumage to refer to residential households with coupled PV units and battery storage (see Schill et al., 2017; Green and Staffell, 2017). Storage connected to the household’s PV unit could absorb excess PV generation that cannot be handled by the grid. However, the mere availability of additional storage in the system is no panacea. In fact, system-beneficial distributed storage operation requires appropriate market and policy designs (Ruester et al., 2014; Groen and Staffell, 2017).

In this paper we focus on the policy design by addressing the following research questions: What is the effectiveness of different policy
schemes to mitigate the need for distribution capacity expansion by incentivizing beneficial storage operation? How cost-efficient are such policies and what are their distributional implications? Analyzing these requires advanced modeling setups, such that strategic interactions between players can be considered. We employ a novel top-down modeling approach that allows us to quantify the effects of regulatory interventions on prosumate dispatch decisions and associated DSO capacity requirements as well as resulting feedback effects on market prices and system costs. To that end, we set up a two-level model that incorporates strategic decisions of DSOs as well as interactions with prosumate, generators, and the transmission level.

We establish a link between bottom-up assessments, which focus on the individual installation level (see, e.g., López Prol and Steininger, 2017; Solano et al., 2018), and system-level analyses, which do not include any representation of the prosumate (Hinz et al., 2018) or the transmission grid level (Kubli, 2018). In our setup, regionally dispersed prosumate is aggregated such that we obtain a representative prosumate within one DSO region. The representative prosumate household participates in an energy-only market with nodal pricing at the level of the high-voltage transmission system. We focus on the prosumate-induced distribution grid requirements, which we model as a dedicated link between prosumate and the transmission network.

In line with the predominant practice in most European countries, for most of our scenarios, we assume the shallow grid charge scheme for the recovery of the initial grid connection cost of prosumate (Hinz et al., 2018). Therefore, costs that arise from DSO link congestion are not passed on to prosumate households, and nodal prices fail to reflect costs induced on the distribution grid level. We take the DSOs’ perspectives and allow them to incentivize prosumate to reduce network congestion. This is distinct from other approaches in the literature, which focus on prosumate self-consumption (Green and Staffell, 2017; Yu, 2018; Solano et al., 2018). We calibrate the model to power system data for Germany for the year 2015 and add proportional storage capacities to each small-scale PV unit. Yet, the general model structure might also be recalibrated to other regions. We assess the effect of different policy scenarios on nodal prices, the required capacity of the DSO link, as well as on overall system costs and distributional implications between different players in the electricity system. As a benchmark, we use a first-best system configuration (Smart scenario), which minimizes system costs. We compare it to the status quo with and without storage, as well as to two feed-in policy scenarios and an autarky case, which assumes self-sufficiency as the goal of prosumate. We provide recommendations on simple policy interventions that support system-friendly prosumate dispatch and that prevent lock-in effects.

The remainder of the paper is structured as follows: The next section situates our work within the related literature. Section 3 provides the model description. Consecutively, we introduce the six modeled scenarios in Section 4 as well as our calibration to German power system data in Section 5. Section 6 presents the solution strategy used to obtain the numerical results, which are provided and discussed in Section 7. Section 8 concludes and elaborates on policy implications.

2. Background and related literature

Our contribution connects two interrelated bodies of literature. On the one hand, it is embedded in the broader literature on options for mitigating the need for distribution grid expansion due to increasing deployment of RES, which we discuss in Section 2.1. On the other hand, it is part of the more specific debate on the merits of residential storage and prosumate, and the system-level implications of its increasing diffusion, which we detail in Section 2.2. In bridging these two bodies of literature, we contribute to the analysis of policy design for distribution grids, which we discuss in the context of the related literature in Section 2.3. Our sophisticated model design bridges the transmission system and the distribution system levels and requires advanced modeling techniques that have only recently been employed in the literature. We detail our contribution to this literature in Section 2.4.

2.1. Options for mitigating distribution grid expansion

An extensive body of literature focuses on the challenges that increasing shares of RES create for distribution networks, and measures that have been proposed to mitigate them (see e.g., Agricola et al., 2012; Klobasa and Mast, 2014; German Federal Ministry for Economic Affairs and Energy, 2014). Resener et al. (2018) provide an extensive review of models for investment and operational planning that aim at optimizing distribution grid capacities given increasing RES feed-in. Instead of long-term capacity expansion, for instance, short-term operations can be altered such that the available grid capacities are sufficient (Spiliotis et al., 2016; Eyer, 2009).

Georgilakis and Hatziargyriou (2015) give an overview on methods and models for distribution grid planning that incorporate distributed RES generation. Of particular interest are studies that focus on the provision of operational flexibility. Knezović et al. (2015) review different options for utilizing flexibility from electric vehicles and discuss their potential to reduce distribution grid capacity requirements. However, the paper discusses general implications for policy design in qualitative terms only and does not provide model-based computations to support its claims. More closely related to our work, Spiliotis et al. (2016) focus on the potential of household demand response to defer grid expansion in the case of two specific distribution networks configurations. von Appen and Braun (2018) analyze strategic investment decisions of 70 households and one DSO. They evaluate different charging schemes for grid costs and the option to curtail PV generation. Both studies disregard effects on the electricity system level. Resch et al. (2017) present an extensive review of potential revenue streams for battery systems in Germany and discuss their ability to provide flexibility under different operation strategies. However, they focus on large-scale battery systems and disregard the feedback between operation strategy, market prices, and system costs.

2.2. Flexibility provision from coupled PV and battery systems

Storage is known for its potential to mitigate network congestion (Virasjoki et al., 2016; Denholm and Sioshansi, 2009; Agricola et al., 2012) also in the distribution grid (Schill et al., 2017; Ruester et al., 2014). However, increasing available storage capacities may also increase required grid capacities (Haller et al., 2012; Neetzow et al., 2018b; Resch et al., 2017). Essential for the interplay between storage and grid is the mode of operation of the storage. Prosumate storage can be charged heuristically during peak PV feed-in or as soon as the PV generation exceeds own demand (Schill et al., 2017; Moshövel et al., 2015). Another option is price-driven operation, where the dispatch decision is triggered by real-time or projected market prices. In turn, the mode depends on market characteristics such as price formation, grid tariffs, and subsidies (Ruester et al., 2014) as well as on behavioral factors such as the goal of self-sufficiency or profit maximization (Graebig et al., 2014).

Furthermore, research has been conducted on the effects of integrated small-scale storage and PV generation, i.e., prosumate. Melgar Dominguez et al. (2018) use an integrated cost minimization approach to optimize PV and storage deployment as well as operation, considering DSO-owned storage in a distribution test network. While general system effects of prosumate are discussed and modeled by Schill et al. (2017), their quantitative analysis omits impacts on the network. More specifically, Moshövel et al. (2015) show the potential to reduce network stress induced by a single prosumate household by cutting off PV peak generation with a beneficial battery-charging strategy. They do not, however, account for feedback effects of the proposed strategies to the overall system. Green and Staffell (2017) focus on the effect of maximizing prosumate self-consumption on
distribution grid requirements and find that it increases capacity requirements. Whereas their work is limited to this extreme case, in the present study we assess a set of different policy options. Also focusing on self-consumption, Yu (2018) finds that prosumage puts business models of incumbent players in the French electricity system under stress.

2.3. Policy design for distribution grids

Along with the literature addressing the technological and economic challenges that come with the restructuring of energy systems towards RES, there is a growing body of literature examining the regulatory interventions and market design changes necessary to make the future system work cost-efficiently (see, e.g., Ruester et al., 2014; Pérez-Arriaga et al., 2017). One strand of this literature is concerned with the efficiency of future electricity systems. MacGill and Smith (2017) provide recommendations for future policy design based on insights from past experience with prosumers' impacts on established electricity market business models in Australia. Also taking Australia as an example, Pollitt (2018) argues that the solution to challenges posed by distributed generation and storage should be a combination of charges for network use and available capacity, as well as marketing of new services. The author highlights the need for modeling to assist in tailoring regulatory intervention. Faerber et al. (2018) detail, based on expert interviews, how distribution network charging schemes should be adapted in the transformation towards smart grids. Focusing on various pricing options to recover network fixed cost, they argue that solutions to the problem might be borrowed from the transmission level.

Smart grids could allow for cost-efficient distribution grid pricing. Brandstätter et al. (2017) suggests a solution to the issue of non-discriminatory data availability, which is one of the central prerequisites for reaping their full potential. Highly granular locational marginal prices (LMP) could indicate the impact of a grid user's decisions on the need for expanding the network (Sotkiewicz and Vignolo, 2006) and cost-efficiently recover investment in network capacity, at least in theory (Bohn et al., 1984; Pérez-Arriaga et al., 2017). However, such a system is not likely to emerge for regulatory, economic, or behavioral reasons (Green and Staffell, 2017). Pérez-Arriaga et al. (2017) argues that LMPs would not be an appropriate mechanism to recover distribution network costs. It would require perfect information on the household level, which raises issues of data privacy. Moreover, their implementation might induce high price differentials even within regions, which may be socially undesirable.

Another strand of literature is concerned with the distributive implications of distribution grid charging schemes. Kubli (2018) assesses the costs induced by further diffusion of prosumage in Switzerland, and analyze how different consumer groups are affected by the recovery of these costs. Similarly, Jargstorf et al. (2015) examines the effectiveness of tariffs to internalize grid costs for prosumage. However, both articles use a system dynamics approach without detailed modeling of the techno-economical interactions on the electricity market. Hinz et al. (2018) apply a detailed electricity market model of Germany to study the effect of alternative cost recovery mechanisms for distribution grids. They check for distributive justice between different regions and assess the implications of charging generators as opposed to charging consumers. While these studies focus on radical changes in the regulatory design for distribution grid, we suggest incremental policy changes that do not deviate from the shallow grid charge scheme. These could prove to be more easily implementable steps towards adapting electricity systems.

2.4. Modeling approach

Analyzing strategic interactions and technical constraints on the interplay between the transmission network, the distribution grid level, prosumage, and generators requires a sophisticated modeling design. Kubli (2018) uses a system dynamics approach but accounts neither for feedback from prosumage dispatch on distribution grid requirements nor for market price effects on prosumage dispatch. Other existing detailed electricity market models either do not incorporate prosumage (Hinz et al., 2018) or lack representation of the transmission grid (Schill et al., 2017).

Our approach follows a hierarchical decision sequence, allowing the DSOs to strategically set policy parameters while anticipating associated market outcomes and dispatch decisions of prosumage and generators. To derive numerical results, this setup is implemented as a two-level game structure, which is necessary to analyze strategic interactions in energy markets and being used to an increasing extent. Cardell et al. (1997) analyze generator market power in the context of transmission constraints. Transmission is disregarded by Bushnell (2003), who differentiates between hydro and thermal generation technologies for strategic interaction, as well as by Schill and Kemfert (2011) and Sioshansi (2014), who examine the interplay between generators and storage. While all the above studies assume that the players act in a simultaneous move game, Wang et al. (2017) analyze a hierarchical setup with a strategic storage operator anticipating her own influence on the market.

All these studies consider strategic operational behavior alone. Strategic transmission investment to mitigate generator market power is additionally taken into account by Jenabi et al. (2013); Huppmann and Egerer (2015); Zerrahn and Huppmann (2017) in multi-level games. While Huppmann and Egerer (2015) consider hierarchical decisions in transmission extension (within-country and between-countries), neither of the studies that consider strategic investment considers distribution grids or storage.

In summary, to our knowledge, there is no approach in the literature to date that comprehensively analyzes interactions between multiple distribution system operators and prosumage within a transmission network and also examines the effectiveness of different regulatory schemes while taking into account the hierarchical market design. Yet, such a comprehensive setup is required to study an appropriate market design that ensures a system-beneficial prosumage operation. We aim to fill this research gap with the paper at hand. Our results are highly relevant to recent debates on the integration of prosumage into energy markets and the importance of regulatory design in shaping this process.

3. Model description

We present the first approach to incorporate network stress on the distribution grid level into a large-scale electricity DC-load flow model. Our setup consists of a multi-nodal TSO network, which connects demand centers and large-scale generation (conventional and renewable). The representative prosumage consists of prosumage demand, small-scale PV, and storage (Fig. 1A) and is connected to the TSO network via dedicated DSO links. The links can be interpreted as the dedicated cumulative DSO capacity necessary to allow prosumage integration into the system. Regional DSOs ensure sufficient DSO link capacity to accommodate all prosumage inflows and outflows. They may incentivize prosumage to reduce its DSO link use via a compensation. We deliberately leave out all other parts of the distribution grid, for instance, those connecting non-prosumage demand (e.g. from non-prosumage households, industry, etc.) or RES to the TSO network (Fig. 1B). The capacities for generation, prosumage, and the TSO network are exogenously given from a calibration and assumed fixed.

3.1. Sets, parameters, variables

A nomenclature for sets, parameters and variables is given in Appendix A. We use lowercase letters for variables (endogenous to the model) and uppercase letters for parameters (exogenous to the model).
Nodes of the TSO network are denoted by \( n, m \in \mathcal{N} = \{1, \ldots, N\} \). Lines connecting the TSO nodes are denoted by \( l \in \mathcal{L} = \{1, \ldots, L\} \). Time slices are denoted by \( t \in \mathcal{T} = \{1, \ldots, T\} \).

### 3.2. The prosumage household’s problem

There is one representative non-strategic prosumage household connected to each of the TSO nodes \( n \). The prosumage household’s objective function is given in Eq. (1) and is the sum of the cost of purchasing electricity on the market to supply own demand \( m2d_{n,t} \) or to be stored in the storage \( m2s_{n,t} \), minus the revenue from selling PV generation \( m2p_{n,t} \) and electricity from storage to the market \( m2m_{n,t} \). Each of these transactions is valued with market price \( p_{n,t} \), which corresponds to the nodal price at the adjacent transmission network node. We assume that prosumage households are price-takers. Note that these prices reflect possible TSO network constraints, but disregard congestion on the DSO level. This constitutes a market failure as prosumage does not properly internalize costs on the DSO level associated with its dispatch. Demand that cannot be satisfied (lost load) \( lol_{PRS,n,t} \) incurs costs of the value of lost load \( \text{VOLL} \).

In addition, the representative prosumage household might receive compensation for an imposed policy that would restrict the prosumage operation. For our particular setup, this is depicted by the term \( \lambda \). We devote Section 4 to explaining the policy-induced compensations in more detail.

\[
\min \text{obj}_{PRS} = \sum_{n,t} \text{VOLL}(m2d_{n,t} + m2s_{n,t} - s2m_{n,t} - p2m_{n,t}) + lol_{PRS,n,t} \cdot \text{VOLL} - (1 - \alpha_{h}) \hat{g}_{h}^{PRS} + \lambda_{h,t}^{PRS}
\]  

(1)

The representative prosumage household is subject to several constraints (given in Appendix B; Eqs. B.1 - B.8). The households own demand can be satisfied by three sources: its own supply from PV generation, from storage, or from the market. Under some circumstances, these might not be sufficient to satisfy demand, resulting in lost load (Eq. (B.1)). For each point in time, PV feed-in can be balanced in four ways: self-consumption, sales to the market, storage, or as a measure of last resort, curtailment (Eq. (B.2)). Eq. (B.3) gives the temporal balance for the storage, where the current energy level equals the previous level reduced by outflows and increased by inflows. The latter are reduced by the round-trip efficiency. The storage capacity cannot exceed the energy storage capacity (Eq. (B.4)). Moreover, storage in (out)-flow cannot exceed its power capacity (Eqs. B.5 and B.6). Eq. (B.7) sets the boundary conditions for storage, where final storage levels have to be equal to initial storage levels. The final Eq. (B.8) depicts the operating constraints that arise from the institutional design. The prosumage feed-in to the market cannot be higher than a fraction \( \alpha \) of its own PV generation capacity (also see Fig. 2). We devote Section 4 to analyzing the respective policy options in more detail.

### 3.3. The generator’s problem

Besides the prosumage household, there is one representative (non-strategic) operator of conventional generation at each TSO node. The operator maximizes its revenue by dispatching conventional generation \( g_{n,t} \) to provide electricity. We assume a quadratic generation cost function \( g_{n,t}/2 - C_{n,t}^{GEN} \) characterized by the cost parameter \( C_{n,t}^{GEN} \). The generated electricity is sold at market price \( p_{n,t}^{TSO} \) (Eq. (2)). Furthermore, the generator is constrained by the available generation capacity (Eq. (B.9)).

\[
\min \text{obj}_{GEN} = g_{n,t}^{2} / 2 - C_{n,t}^{GEN} - g_{n,t}^{TSO} p_{n,t}^{TSO}
\]

(2)

### 3.4. The DSO’s problem

The DSO is in charge of the link that connects the prosumage household to the TSO node, which has a capacity \( f_{n,t}^{DSO} \). The objective of the DSOs is to minimize capacity costs of the DSO link as well as compensation costs paid to incentivize the prosumage household to reduce its network use. To account for the length of the capacity planning horizon, marginal capacity investment costs \( MC^{DSO} \) are multiplied by the number of hours considered, i.e., the cardinality of \( t \) (Eq. (3)).

\[
\min \text{obj}_{DSO} = \sum_{n,t} \text{obj}_{DSO}^{DSO} = f_{n,t}^{DSO} \cdot MC^{DSO} \cdot \mathcal{F} + \sum_{t} (1 - \alpha_{h}) \hat{g}_{h}^{PRS} \lambda_{h,t}^{PRS}
\]

(3)

This is subject to two balance constraints: one for the inflow, i.e., from the TSO node to the prosumage household (Eq. (B.10)), and one for outflows, i.e., from the prosumage household to the TSO node (Eq. (B.11)). Eq. (B.10) ensures that DSO link capacity is large enough for the inflow. Eq. (B.11) is connected to the policy design and obtains its effectiveness in connection with Eq. (B.8). It guarantees a minimum share of \( \alpha \) of the maximum PV generation capacity for prosumage as admissible outflow (also see Fig. 2).

1 The parameter \( C_{n,t}^{GEN} \) thus describes a linear marginal cost function of the form \(\hat{g}_{h}^{PRS} \lambda_{h,t}^{PRS} \).

2 In reality, the DSO is responsible for supplying grid connectivity for all types of consumers, not only prosumage households, but also regular households, industrial operations, as well as utility-scale renewable generation. In this paper, we focus on the interaction among prosumage households, DSO, and TSO. Therefore, we aggregate residual demand \( D_{n,t} = C_{n,t}^{GEN} \) (excluding prosumage) to the TSO node level.
3.5. Balancing by the TSO

Finally, the TSO ensures cost-efficient balancing of the flows in the TSO network, which follow the usual linearized DC-flow approach of Kirchhoff's Laws (see, e.g., Schweppe et al., 1988). The nodal balance is given in Eq. (B.12). Here, the residual non-prosumage demand is given by non-prosumage demand minus potential generation from RES. As in the prosumage household's problem, we allow for curtailment and lost load in case there is an excess or a shortage of power. Line flows and imports are calculated using network transfer and susceptance matrices as well as the nodal phase angle difference to a swing node (Eq. B.13, Eqs. B.14 and B.17). TSO line capacity has to accommodate positive and negative TSO network flows (Eqs. B.15 and B.16).

3.6. Model structure

The interactions between DSO and prosumage necessitate a two-level model structure. On the lower decision level, conventional power generators and prosumage are price-takers and Stackelberg followers in an equilibrium energy-only market. Acting as Stackelberg leaders on the upper decision level, i.e., anticipating the lower level reactions, regional DSOs balance incentive payments and required link capacity. Thereby, they may change the equilibrium of the lower level, i.e., the dispatch decisions of generators and prosumage households. Mathematically, this setup constitutes a Mathematical Program under Equilibrium Constraints (MPEC) for each of the DSOs.

The TSO network connects the DSOs and ensures balancing. Thus, the DSOs’ decisions (optimal strategies) are not mutually independent either: The chosen policy of one DSO will influence the choices of others, as a more restrictive capacity in one region and resulting higher nodal prices might incentivize an increase in prosumage feed-in in other regions. This, in turn, would increase the compensation required to make local prosumage households indifferent. Enforcing an equilibrium between the DSOs would require solving an Equilibrium Program under Equilibrium Constraints (EPEC) (Ruiz et al., 2012). Solution methods for EPECs are currently limited to small-scale applications (Gabriel et al., 2012). We leave the exact solution of this problem to future research, as the purpose of the paper at hand is to provide empirically relevant results for large-scale systems. In this paper, we approximate the EPECs solution by decoupling the respective DSO problems and instead solve a set of separate two-level MPECs (see Section 6).

3.7. Scenarios

In this section, we introduce six scenarios to evaluate different policy mechanisms: Smart, No storage, No policy, Autarky, KfW policy and DSO-wise policy. Table 1 provides an overview. While Smart, No storage and No policy can be implemented as single-level optimization problems, Autarky, KfW policy and DSO-wise policy incorporate strategic interactions between players in a Stackelberg leader-follower setting, and thus require a more sophisticated solution approach.

The Smart scenario provides a benchmark in which total system costs are minimized. To this end, Smart envisions a power system setup, where storage systems are available in prosumage households and a first-best pricing mechanism is implemented. In our setup, this is equivalent to a capacity tariff, which prosumage households have to pay for using the DSO grid. Consequently, the interaction of prosumage household demand, generation and storage dispatch, as well as DSO grid expansions are fully taken into account. The No storage scenario assumes the same system cost minimizing perspective of the TSO as in the Smart scenario, but, in contrast to all other scenarios, there is no prosumage storage capacity available in the system. In the No policy scenario, DSO capacity and respective costs are excluded from the TSOs consideration. This scenario represents a situation in which dispatch decisions on the prosumage level are driven by the market prices, i.e. derived from locational marginal costs at the TSO nodes. Thus, prosumage households do not account for their effect on DSO capacity requirements.

In contrast to the first three, the remaining scenarios incorporate the two-level Stackelberg game structure. Interaction is reflected in the compensation terms of their objective functions as well as Eq. (B.8), which imposes an operational constraint on prosumage, reducing the admissible feed-in to the market (Fig. 2). The adequate choice of the policy variable \( \alpha_n \) can reduce the market failure induced by the prosumage household disregarding DSO capacity costs. If \( \alpha_n \) is large there are no or few restrictions on grid feed-in from prosumage, while for \( \alpha_n = 0 \) no feed-in is allowed.

In the Autarky scenario, prosumage is determined to maximize self-sufficiency, i.e., the share of own PV generation in its demand (see Luthander et al., 2015), and to reduce market interactions. This can be represented by \( \forall n: \alpha_n = 0 \). As a consequence, prosumage will never feed into the DSO link and will instead use storage to satisfy its own demand from its own generation. Yet, if demand cannot be met by either PV generation or storage, prosumage can still purchase electricity from the market using the DSO link. Even though the Autarky scenario imposes operational costs on prosumage, we abstain from compensating payments as we assume that the autarky decision is made by the prosumage household for non-monetary reasons (Graebig et al., 2014).

In the KfW policy scenario, the policy is exogenously set for all DSOs such that \( \forall n: \alpha_n = 0.5 \). The name is chosen in analogy to a storage promotion program that is in place in Germany and supported by the state-backed investment bank KfW. As a consequence, prosumage feed-in is limited to half the available prosumage PV capacity. This, in turn, reduces the required distribution grid capacity and therefore grid investment costs. Yet, the restriction of the prosumage households’ dispatch decisions might reduce revenues. The shadow price \( \lambda_{PV}^* \) of Eq. (B.8) provides a unit of measurement for the foregone marginal revenue due to the imposed restriction. To compensate the prosumage household for this loss, we include the compensation payment...
Table 1
Overview of scenarios by storage availability, game structure, maximum feed-in as well consideration of DSO link costs. While in No storage and Smart, prosumage feed-in is optimized from a total system cost perspective, it is unrestricted in No policy, set to a generic limit in KfW policy, and is set to a DSO-specific limit in DSO-wise policy. No prosumage feed-in is allowed for the Autarky scenario.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Storage</th>
<th>Max. prosumage feed-in</th>
<th>Compensation¹</th>
<th>Costs of DSO link</th>
<th>Game structure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Smart</td>
<td>✓</td>
<td>optimized</td>
<td>implicit</td>
<td>fully internalized</td>
<td>min system cost</td>
</tr>
<tr>
<td>No storage</td>
<td>✓</td>
<td>optimized</td>
<td>implicit</td>
<td>fully internalized</td>
<td>min system cost</td>
</tr>
<tr>
<td>No policy</td>
<td>✓</td>
<td>unrestricted</td>
<td>n/a</td>
<td>partly avoided</td>
<td>Stackelberg game</td>
</tr>
<tr>
<td>Autarky</td>
<td>✓</td>
<td>no feed-in</td>
<td>n/a</td>
<td>partly avoided</td>
<td>Stackelberg game</td>
</tr>
<tr>
<td>KfW policy</td>
<td>✓</td>
<td>generic limit</td>
<td>explicit</td>
<td>partly internalized</td>
<td>Stackelberg game</td>
</tr>
<tr>
<td>DSO-wise policy</td>
<td>✓</td>
<td>DSO-specific limit</td>
<td>explicit</td>
<td>partly internalized</td>
<td>Stackelberg game</td>
</tr>
</tbody>
</table>

¹ Compensation for prosumage dispatch restrictions by DSO.

\[ \sum (1 - \pi_n) G_{n}^{PRS} x_{n}^{PRS} \] from the DSO to the prosumage household. As the desired grid feed-in from the prosumage household is unknown to the DSO, it compensates up to the maximum potential feed-in inhibited by the policy \( (1 - \pi_n) G_{n}^{PRS} \), making the prosumage household at least indifferent compared to a scenario without a policy.

In the DSO-wise policy scenario, we assume that \( \pi_n \) can be chosen freely by the nth DSO, i.e., every DSO restricts the dispatch of its associated prosumage. Again, we assume that the respective DSO has to compensate the prosumage household. The compensation scheme is the same as under the KfW policy. Yet, the DSO-specific choice allows each DSO to balance costs for capacity investment and prosumage compensation. The compensation increases the more restrictive the policy gets: on the one hand directly from a decreasing \( \pi_n \), and on the other hand indirectly from the increase of shadow price \( \lambda_{n,t}^{PRS} \), which is a function of the market price \( \pi_{n,t}^{PRS} \).

4. Model calibration

We calibrate the model with state-wise (Bundesland) aggregated data on the German electricity system (i.e., \( n \in \mathcal{N} = \{ \text{BB, BE, BW, BY, HB, HE, HH, MV, NI, NRW, RP, SH, SL, SN, ST, TH} \} \), for the year 2015. Hence, we assume that the distribution grid of each respective state is operated by one DSO.⁵ Wherever possible, we use the electricity data provided in Kunz et al. (2017). The relevant available data on conventional plants, renewable energy capacities,⁶ time series for wind feed-in, demand, as well as properties of the transmission grid are all aggregated to a state level. Furthermore, for each state, we estimate a linear approximation to its unit level merit order curve using a least-squares fit. The derived marginal generation costs are corrected for the availability of generation capacities and therefore are time-dependent. The value of lost load \( VOLL \) is assumed to be 200 EUR/MWh.⁷ We allocate all PV-systems ≤ 10 kW which amount for 5.8 GW (Open Power System Data, 2018)⁸ to prosumage. For the purpose of our analysis, we assume that each of these PV systems is accompanied by proportional storage capacities (in total 2.9 GW, 11.6 GWh) with a round trip efficiency of 0.9. To test the soundness of our findings, we additionally conduct a sensitivity analysis on the storage power capacities (for 1.45 GW and 5.8 GW).

State-level, capacity-normalized time series for PV feed-in are taken from Koch et al. (2016).⁹ We approximate the share of household consumption in load by BDEW household standard load profiles (Bundesverband der Energie-und Wasserversorgung e.V., 2015) and total German household consumption in 2015 (Umweltbundesamt, 2017). Finally, prosumage demand is approximated by the state-wise number of PV-systems ≤ 10 kW (Open Power System Data, 2018) and by assuming the average yearly demand of a single prosumage household to be 5 MWh, which is in line with Beck et al. (2016); Bertsch et al. (2017). DSO unit investment costs are assumed to be 2 EUR per MW and hour.¹⁰ However, we also provide sensitivities for 1 and 4 EUR per MW and hour. An overview of parameters is given in Appendix C.¹¹

We compute a whole year with an hourly temporal resolution. However, for computational reasons, we do not compute all hours of the year at once but solve all days separately. To make all days \( \tau \in \{1, \ldots, 365\} \) independent of one another, we fix the energy levels of all storage capacities at the end of every day to their initial energy levels (see Eq. (B.7)) and assume \( E_{n,t}^{PRS} = E_{n,t}^{PRS,0} \).

5. Solution strategy

In the following, we explain the individual model reformulations and steps that are necessary to solve the mathematical problems defined by the different scenarios. More detailed descriptions including comprehensive equations are given in Neetzow et al. (2018a).

We solve the scenarios Smart, No storage and No policy as non-linear (quadratic) system cost minimization problems (NLP) for each day. To implement the No storage scenario, we parametrize \( E_{n,t}^{PRS} = E_{n,t}^{PRS,0} = 0 \), such that no storage capacity is available. Finally, the No policy scenario neglects DSO capacity constraints and associated costs in its objective. Here, we compute the required DSO capacity ex post from the maximum flow that occurs on the DSO link.

The remaining scenarios require multi-level solution techniques. We abstain from solving the inter-DSO coordination problem by fixing all imports into a DSO region \( im_{n,t}^{DSO} \) to values obtained in the Smart scenario and by adjusting the generation parameters \( x_{n,g,t}^{GEN} \) and \( E_{n,t}^{GEN} \) such that regional generation can be increased at market price. The

—

⁵ German Federal States: Brandenburg (BB), Berlin (BE), Baden-Württemberg (BW), Bavaria (BY), Hesse (HE), Bremen (HB), Hamburg (HH), Mecklenburg-West Pomerania (MV), Lower Saxony (NI), North Rhine-Westphalia (NRW), Rhineland-Palatinate (RP), Schleswig-Holstein (SH), Saarland (SL), Saxony (SN), Saxony-Anhalt (ST), Thuringia (TH).

⁶ Even though there are about 890 different DSOs in Germany (BNetzA, 2018), we reduce complexity while maintaining DSO diversity by using this assumption.

⁷ We consider the renewable technologies run-off-river, biomass, geothermal, hydro, and waste as non-dispatchable units with partly seasonal availabilities.

⁸ We consider that \( VOLL \) might appear low compared to, e.g., London Economics (2013), it exceeds the maximum unit generation costs. Thus, an increase of \( VOLL \) would have no effect on the occurrence of lost load due to inelastic demand. Furthermore, for the recent model calibration, we find no lost loads.

⁹ We derive the share of PV-systems ≤ 10 kW from (Open Power System Data, 2018) but use the data on total capacity from Kunz et al. (2017), the study uses the weather year 2011 and the predicted distribution of PV-systems in 2020.

¹⁰ This figure is based on calculations from Klobasa and Mast (2014). The study reports 1.4 bn EUR of additional annual investment requirements for distribution grid expansions in order to integrate a capacity of 92.1 GW in PV and wind generation for the period up to 2020. In the future, they assume these requirements will increase further by about 50 % up to 2030. Distributing costs over examined hours gives us a value of ≈ 2 EUR per MW of installed RES capacity (or potential RES feed-in) and hour.

¹¹ The model and a comprehensive dataset can be found under https://doi.org/10.18452/20118.
remaining mathematical problem is an individual MPEC for each DSO region. We solve the MPECs as mixed-integer linear problems (MILP) using disjunctive constraints (Fortuny-Amat and McCarl, 1981) and through a discretization of the feasible realizations of $\alpha_r$.

We implement the problems in GAMS and use the commercial solvers CONOPT for NLP and CPLEX for MILP. Computation time is about 30 h for the scenario simulations of one year (System: quad-core CPU 2.8 GHz, 16 GB RAM).

6. Results and discussion

The following section presents modeling results and discusses possible implications. First, we focus on one particular day and one region to detail the general mechanisms that drive the effects of the different policy options on prosumage storage dispatch. We find that the DSO capacity requirement is especially high during the morning hours when PV generation starts to ramp up while price-driven storage is discharging. Subsequently, we compare the efficiency of the policies examined for different DSO networks. Even though the outcomes of the policy mechanisms are largely consistent overall, quantitative results on capacity reduction potential and necessary compensation differ substantially. Looking at daily required DSO link capacity aggregated across regions, we find that storage exerts ambiguous effects that depend crucially on the policy choice. While smart operation of storage reduces capacity needs, these are increased if no policies are implemented. Feed-in policies are also effective in reducing capacity requirements but reach their limit at the point where loads dominate the grid needs. Another important cost driver consists in operational restrictions, which increase system costs for No storage and Autarky in particular. Finally, we evaluate effects on the electricity system level and distributional implications for different players. Compared to no policy, simple feed-in policies are able to close about half the gap towards a minimum-cost system. While non-prosumage demand and RES policy, simple feed-in policies are able to close about half the gap towards a minimum-cost system. While non-prosumage demand and RES generally benefit from storage availability, this result does not hold for the demand under Autarky.

6.1. Policy mechanisms at the individual DSO level

To analyze the mechanisms behind the policies, we first focus on the effects on one particular day and region. We chose the weekday with the highest PV generation – Monday, May 25 – and focus here on the results for Bavaria, which has about 13 GW of PV capacity deployed. Fig. 3 shows the realized nodal prices, storage dispatch, and flows in the DSO link for each of the scenarios.

Prices for all scenarios show the typical duck curve pattern (California ISO, 2016) with higher prices in the morning and evening demand peaks and depressed prices during the day due to PV feed-in. The No storage scenario exhibits the most pronounced peaks and valleys. When storage is introduced into such a system, it allows for intertemporal shifting and thereby reduces price extremes (peaks and valleys are less pronounced in all other scenarios). Prices as well as storage operation are similar for the scenarios Smart, No policy, KfW policy and DSO-wise policy, and differences mainly arise during few hours when the DSO capacities are highly stressed. Interestingly, this is not necessarily the case during times of very high PV generation, as the associated low prices can provide sufficient incentives for market-driven prosumage storage to be charged, and thus mitigate high feed-ins. Instead, differences occur during the morning hours at about 8-9 AM. Here, PV generation already exceeds a third of the daily peak but prices are still relatively high. Therefore, in a scenario in which grid stress is disregarded (No policy), storage is further discharged, leading to additional distribution grid stress. Remarkably, in this scenario, peak grid feed-in is even higher than in the No Storage scenario. Those scenarios that take the DSO capacities into account (Smart, DSO-wise policy, KfW policy) show lower storage discharge for these hours. This, in turn, reduces the feed-in and grid requirements and indicates the effectiveness of the policies.

The Autarky scenario exhibits similar prices to the No storage scenario, except for the mid-day hours, where the price valley is less pronounced due to the prohibition of market feed-in from prosumage. In particular, excess prosumage PV generation that cannot be stored must be curtailed. As a consequence, the storage utilization is much lower than in the other storage scenarios and not driven by price differentials like in the other scenarios. Lastly, it is the only scenario without any market interaction. In addition to the prohibition of feed-in, also no purchase from the market is needed for the day considered, such that prosumage is fully self-sufficient and does not need any DSO capacity. However, this picture changes for days with lower PV generation.

6.2. Comparing results for different DSO networks

Next, we compare results between different states, which resemble separate DSO networks. The optimal trade-off between flexibility provided by the prosumage storage and required DSO capacity is driven by the local share of prosumage in residential demand, local generation patterns, weather conditions, and transmission grid characteristics. Fig. 4 shows the maximum allowable feed-in shares $(a)$ for the Smart, No policy, KfW policy, and DSO-wise policy scenarios and induced compensation payments for the latter two. For the majority of states, the required feed-in capacity is lowest in the Smart scenario, followed by KfW policy, DSO-wise policy, and the No policy scenario. Hence, the qualitative pattern that was described above for Bavaria generally
Quantitatively, however, there are great differences among the states and thus among the different DSOs. Particularly in states with high demand, high PV generation, and high prosumage shares (BW, BY), DSOs need to provide relatively high compensation to reduce prosumage feed-in. In other large states that have lower PV deployment and prosumage shares (NI, NRW), the compensation is also smaller. Also, the policy’s effectiveness for different DSOs varies. While in Thuringia (TH), the feed-in reduction potential is substantial, in Lower Saxony (NI) it turns out to be very low, especially for the DSO-wise policy scenario.

6.3. Aggregate results on DSO capacities

With a good understanding of the underlying mechanisms, we can now focus on the policies’ state-aggregate effects on DSO capacity requirements. Fig. 5 depicts the sum of daily necessary DSO capacities for all regions throughout the entire year, while Fig. 6 gives the share of required DSO capacity which is feed-in-driven. In the benchmark scenario without storage (No storage), we find the highest grid requirement in summer, driven by high PV grid feed-in. In fact, in about half of the time, DSO capacity is exclusively driven by feed-in in this scenario. Introducing storage into the system substantially decreases required DSO capacities in the scenario Smart. However, the picture changes in the case of purely self-optimizing prosumage (No policy). Here, capacity requirements do increase, not only compared to Smart but also in reference to the No storage scenario and a substantial share of DSO capacity requirements comes as a consequence of feed-ins. Consequently, additional storage capacities can have ambiguous effects on DSO capacities that depend on their mode of operation.

Looking at the scenarios KfW policy and DSO-wise policy, we find that they are effective in mitigating capacity requirement peaks compared to No policy during the summer months (April–September) with all regions throughout the entire year, while Fig. 6 gives the share of required DSO capacity which is feed-in-driven. In the benchmark scenario without storage (No storage), we find the highest grid requirement in summer, driven by high PV grid feed-in. In fact, in about half of the time, DSO capacity is exclusively driven by feed-in in this scenario. Introducing storage into the system substantially decreases required DSO capacities in the scenario Smart. However, the picture changes in the case of purely self-optimizing prosumage (No policy). Here, capacity requirements do increase, not only compared to Smart but also in reference to the No storage scenario and a substantial share of DSO capacity requirements comes as a consequence of feed-ins. Consequently, additional storage capacities can have ambiguous effects on DSO capacities that depend on their mode of operation.

Fig. 4. State-wise DSO capacity as share of PV peak generation ($\sigma_n$) and compensation payment for May 25. In the DSO-wise policy, $\sigma_n$ is greater than for KfW policy in most cases. If distribution stress is solely driven by loads, both policies are ineffective and there is no compensation.

Fig. 5. Daily necessary DSO capacity. While in the base case scenarios DSO capacity requirements are PV driven and highest during the summer months, all policy scenarios have lower capacity needs during summer compared to winter. Maximum Smart capacity = 2.6 GW.

12 Except for the small state Bremen, in which load rather than feed-in is the determining factor.

13 Note that for the entire year, even larger capacities than the daily maxima might be needed if the state-wise maximums do not coincide.
high PV generation. As these account for the highest capacity requirements, the policies manage to reduce the needed capacity. Comparing the two scenarios, the fact that the DSO-wise policy scenario has a higher level of feed-in-induced capacity requirements suggests that the KfW policy policy is overly restrictive. For both scenarios, the remaining grid requirement peak now occurs during the winter months (October–March) and is mainly driven by prosumage load (i.e., flows from the market to the prosumage household) (Fig. 6), which the policies cannot affect. As a consequence, also a yearly optimization – as opposed to the day-by-day consideration – could not reduce the needed DSO capacity in the DSO-wise policy or KfW policy scenario. An exception arises if storage capacities are low (see Figures D.10 and D.12). Here, peak grid use in the KfW scenario still occurs during summer feed-in and can effectively be mitigated by the DSO-wise policy.

In the Autarky scenario, DSO capacity requirements are fully driven by load as there exists no feed-in (see Fig. 6). During summer, the DSO capacity requirement is reduced substantially, amounting to more than 100 days without any need for DSO capacity. Nevertheless, the scenario is not very effective in reducing load-driven capacity needs during days with very low PV generation as long as seasonal storage is not available. Eventually, almost as much DSO capacity has to be deployed as with the other policies or in the No storage scenario.

6.4. System costs and distributional effects

To analyze the system-level effects of the different policy options, we look at the change in yearly system costs and players’ objectives compared to the Smart scenario (Fig. 7). To do this, we convert the obtained daily capacities (Fig. 5) to yearly values. In the scenarios No storage, No policy, Autarky and KfW, the DSOs must provide the peak utilized capacity throughout the entire year, while the peak capacities in Smart and DSO-wise policy could still be reduced, e.g., by increasing compensation to save yearly investments. To account for these differences, we compute the yearly costs and objectives for No storage, No policy, Autarky and KfW using the peak capacity and for Smart using the mean daily capacity.¹⁴ For the DSO-wise policy, summer feed-in peaks might be reduced by stricter policies, but winter loads cannot. We thus use the peak capacity from 21.9.–21.3. Throughout the whole year.

From the analysis above, we know that maximum DSO capacity requirements associated with the market interactions of prosumage are about the same for the scenarios No storage, KfW policy, DSO-wise policy, and Autarky. Therefore, necessary capacity investment costs compared to the Smart scenario are similar for these four scenarios as well. However, they differ in the dispatch of generation and storage units, and consequently also in associated operation costs. We find that system costs in the scenarios DSO-wise policy and KfW policy increase by 0.5 percentage points compared to Smart. With a 0.9 percentage points increase, the rise in costs is substantially higher in the No policy scenario. For these three scenarios, the increase comes solely from inefficiently high distribution grid capacities, while operational costs

¹⁴ This method may slightly over- or underestimate the actual capacity needs in Smart.
decrease. This phenomenon arises due to the greater operational freedom of prosumage storage (higher distribution grid capacity allows more market interaction), which leads to a reduction in generation costs due to the consideration of the TSO nodal prices. In the Smart scenario, this freedom is restricted as a means to achieve the lower, cost-efficient distribution grid capacities.

Clearly, the mechanisms change substantially for No storage and the Autarky scenario with its severe restrictions on market interaction. For both of them, operational costs increase substantially. In the No storage scenario, that increase is driven by the fact that expensive peak generation during high demand hours cannot be substituted by cheaper off-peak generation using storage. In the Autarky scenario, storage operation is also heavily restricted. Besides that, excess prosumage PV generation is no longer available to the market, which leads to curtailment and adds to increasing operational costs.

Testing the sensitivity of these results (see Appendix D.2) on changing storage power capacities and distribution grid capacity unit costs, we find that a ceteris paribus increase (decrease) of both parameters, respectively, implies a more (less) pronounced change in total system cost compared to Smart. For instance, with double storage capacities system costs under DSO-wise policy and KfW policy increase by 1.1 %, under No policy by 1.5 % compared to Smart. For double DSO costs, we find an increase of 1.2 % for DSO-wise policy and KfW policy and of 1.7 % for No policy compared to Smart. Thus, while the qualitative cost-saving effects of the policies are robust, their quantitative effectiveness does not proportionally increase with higher storage capacities or DSO unit capacity costs.

Finally, we assess the beneficiaries and losers of different scenarios. We have seen before that DSO costs from investment are rather similar for the scenarios No storage, Autarky, KfW policy and DSO-wise policy and about 115 % higher than in the Smart scenario. Taking the costs of compensating prosumage into account as well adds another 8 % to the KfW policy scenario, and 4 % under the DSO-wise policy (Fig. 8, left). Particularly, due to the compensation, prosumage-households are slightly better off under the KfW policy. However, the improvements from the increased operational freedom in the No policy, KfW policy, and DSO-wise policy scenarios compared to the Smart scenario are small at <10 %. In contrast, prosumage households lose substantially if aiming for Autarky due to lost PV revenues and inefficient storage operation.

Let us now also take a look at non-prosumage demand and renewable generators. We define their objectives as

\[ \text{obj}_D^n = \sum_t \left( D_{h,t} - l o l_{h,t}^{TSO} \right) P_{h,t}^{TSO} + l o l_{h,t}^{VOLL} \]  

\[ \text{obj}_{RES} = - \sum_t \left( G_{h,t}^{RES} - c u r_{h,t}^{TSO} \right) P_{h,t}^{TSO} \]  

(4)

(5)

Renewable generation and non-prosumage demand both lose in the No storage scenario by 0.5 % and 0.3 % respectively relative to Smart (Fig. 8, right). This shows that storage facilitates renewable capacity deployment (see, e.g., Denholm and Hand, 2011), while conventional generators lose (Sioshansi, 2010).\(^{15}\) Renewable generators also gain substantially in the Autarky scenario because the prosumage PV curtailment increases prices, particularly when there is also a substantial amount of generation from non-prosumage PV. From the demand perspective, however, these higher prices induce higher costs. Finally, the two players are relatively indifferent between the scenarios Smart, No policy, KfW policy and DSO-wise policy, with their objectives deviating by below 0.1 %.

6.5. Limitations

Our model setup and calibration rely on some critical assumptions that need to be borne in mind when interpreting the results. For the parametrization of DSO investment costs, we assume unit capacity costs and therefore disregard the economies of scale that are inherent to this infrastructure investment. Taking these into account would reduce system cost differentials between scenarios with high and low distribution grid requirements, while our qualitative results would still hold. Even though we use Germany to calibrate our model, we deviate from some institutional conditions of the national electricity market, such as the single bidding zone. To derive more nuanced estimates on the effects of market structures, the model can be further adapted to the regulatory settings of the region. Furthermore, it can be recalibrated to analyze other target regions. However, we are confident that our qualitative findings are widely robust for different market structures as well as other regions.

\(^{15}\) Exceptions to this rule may arise, e.g., if storage is owned by oligopolistic generators (Schill and Kemfert, 2011).
In our representation of storage, we assume that operational conditions do not change over time and do not account for capacity degradation. Reducing the depth of discharge or charging rates can increase battery life (Choi and Lim, 2002) but would also have impacts on the electricity system level. Moreover, we assume that the choice of battery size is independent of the regulatory design, which is aimed at battery dispatch. We leave the assessment of incentives for private storage investment to future research, as this would further complicate the already complex game structure of our setup.

Contrary to small-scale DSO system and prosumery analyses on the individual home or community level, our approach uses a coarse DSO representation but allows us to draw conclusions for a large system. We are aware that our model does not capture all technical aspects of distribution grid management, such as voltage regulation, power factor correction, or the reduction of energy losses (Resener et al., 2018). Moreover, we disregard DSO capacity needed for non-prosumatic demand or other small-scale generation. We also abstract from the range of voltage levels handled by DSOs (from the household level at 230 V to the high-voltage level at 110 kV for Germany) for regional distribution and interconnection. In a trade-off between complexity and tractability, we aggregate the individual components of the distribution grid, comprised, e.g., of distribution lines, transformers, and capacitors. Moreover, our approach simplifies the resulting coordination problem arising among the different DSOs when setting the individual feed-in restriction. With the methods described in Section 6, we enforce an equilibrium between the DSOs, but there might well exist other equilibria that we do not explore here.

7. Conclusions and policy implications

The increasing number of residential PV systems paired with storage (prosumage) has great potential to benefit the electricity grid as well as the energy system as a whole. Prosumage households provide private capital for both renewable energy and storage deployment and thus play an important role in the modernization of power systems. Furthermore, household ownership may improve the general acceptance towards RES (Mussall and Kuik, 2011). As residential battery storage systems become increasingly available and financially viable (Muezel et al., 2015), the structures of production and storage ownership are inverted, and the technical system characteristics change as well. There is no longer a clear hierarchy, with large conventional generators at high voltage levels and successive transmission and distribution to the consumers. Instead, decentralized generation – especially from renewable sources – is fed in along all voltage and grid levels of the system. In this paper, we have analyzed how such storage options can contribute to the integration of RES into a future power system by mitigating distribution grid use and thus facilitating diffusion without the need for grid expansions. Realizing the potential of storage is accompanied by both technical and institutional challenges. To analyze these, we have deployed a comprehensive multi-level capacity planning and dispatch model that mimics the interplay between conventional demand and prosumage, conventional generation and renewables, as well as the DSO and the TSO grid levels. The model accounts for institutional settings and decision-making power of the different players.

Our analysis shows that if storage is deployed without appropriate policies, significant potential system benefits are left untapped. In particular, much of the positive price-moderating effect of storage is eaten up by additional distribution grid requirements. We advise policymakers to provide legal conditions that incentivize prosumage households to operate storage in a system-beneficial manner, e.g., by restricting grid feed-in from PV generation. Simple policies like the restriction of maximum grid feed-in based on the nominal PV generation capacity (our KfW policy scenario) are effective in mitigating DSO stress from high prosumage feed-ins. Feed-in policies are, however, ineffective in regulating load-driven DSO stress, e.g., due to high prosumage demand and storage charging from the market at times with low PV generation. As a consequence, even more elaborate feed-in policies cannot further reduce DSO capacity needs substantially. In particular, this holds for high storage capacities (cf. Appendix D.1). Consequently, complementary load policies are needed, that are able to restrict power purchases from the prosumage household, particularly for charging the storage. This is also reflected by the decreased policy effectiveness for larger storage capacities. In general, we like to caution decisionmakers when making decisions about storage, as it contributes to both, load as well as feed-in, and may potentially aggravate both kinds of DSO stresses if no respective operational restrictions or incentives are in place.

Neglecting distribution grid costs (No policy scenario) induces a system cost increase of about 0.9 % compared to a system-optimizing perspective (Smart scenario). Doubling storage capacities increases this figure to 1.5 %. Under both storage options, the increase can be reduced by about half a percentage point if simple feed-in policies (KfW policy, DSO-wise policy) are implemented. Even though these effects are rather small in absolute terms, it is important to note that the changes are all driven by prosumage households, who only contribute about 1 % of total generation and demand.\footnote{In our parametrization, it is annual prosumage demand: 4.9 TWh, prosumage PV generation: 6 TWh, total system demand (incl. PRS): 515 TWh.} A higher share of prosumage households will likely induce a respective increase in costs. Significant differences between policy interventions are apparent when looking at the distributional effects on prosumage households and DSOs. While prosumage autarky is more beneficial to the DSO than an unregulated scenario, the prosumage household is worse off. In contrast, policies with incentive payments improve the DSO situation compared to the unregulated scenario and the prosumage situation compared to the Autarky scenario.

In a nutshell, decision makers should be cautious about the following aspects: 1) Prosumage has a great potential to shape the future power system and facilitate its transition towards sustainability. 2) Nevertheless, prosumage may also have adverse effects, such as associated increase in distribution grid requirements. 3) To tap the full potential of advantages from prosumage, appropriate policies are needed. Feed-in policies can be utilized to partly mitigate grid needs but must be complemented by load policies to realize the full potential. 4) Careful policy design is vital: otherwise, system costs might even increase with storage.

These findings open up multiple promising avenues for future research: First, this analysis could be extended to include one or multiple load policies. It is likely that even a simple load policy would allow further reductions in DSO capacity needs by addressing cases in which they are driven by peak load in the current scenarios. For instance, one may restrict the amount of combined prosumage demand and storage charging from the grid in a similar fashion as the maximum feed-in is restricted. It is straightforward that the same cap for load and feed-in DSO grid use should be implemented to use the capacity efficiently. Again, any operational restriction should be appropriately compensated. Focusing more on loads also opens the option to look at the influence of electric vehicle diffusion, which will likely play a major role in future DSO capacity planning.

Moreover, the model can be used to assess the effects of different storage ownership structures (independent vs. prosumage vs. DSO vs. TSO), which may change the incentives for its dispatch and thus imply effects on system operation costs, grid capacity requirements, and distribution of rents. Another promising avenue for further research is the coordination required between different DSOs (a policy set by one DSO may have impacts on prices and thus influence required incentive payments by other DSOs) and the path-dependency that would be implied by any uncoordinated decision making. Furthermore, the incentives arising from the distribution of network charges could be
further investigated. This would allow for an investigation of the trade-off between private storage capacity investment and different possible revenue streams and avoided costs on the prosumage side. In this context, also additional revenue streams for prosumage households such as balancing markets or other system services could be assessed.

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**Appendix A. Nomenclature**

**Table A.2**

Sets and parameters used in the model.

<table>
<thead>
<tr>
<th>Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Sets</strong></td>
<td></td>
</tr>
<tr>
<td>$n, m \in \mathcal{N} = [1,...,N]$</td>
<td>TSO nodes</td>
</tr>
<tr>
<td>$t \in \mathcal{T} = [1,...,T]$</td>
<td>Days of the year</td>
</tr>
<tr>
<td>$r \in \mathcal{R} = [1,...,365]$</td>
<td>Days of the year</td>
</tr>
<tr>
<td>$t \in \mathcal{F} = [1,...,8760]$</td>
<td>Hours of the year</td>
</tr>
<tr>
<td><strong>Parameters</strong></td>
<td></td>
</tr>
<tr>
<td>$D_{n,t}^{PRS}$</td>
<td>Demand from prosumage [GW]</td>
</tr>
<tr>
<td>$G_{n,t}^{PRS}$</td>
<td>PV generation from prosumage [GW]</td>
</tr>
<tr>
<td>$E_{n,t}^{PRS}$</td>
<td>Prosumage PV capacity [GW]</td>
</tr>
<tr>
<td>$D_{n,t}^{RES}$</td>
<td>Energy capacity of storage [GWh]</td>
</tr>
<tr>
<td>$E_{n,t}^{RES}$</td>
<td>Storage power capacity [GW]</td>
</tr>
<tr>
<td>$\eta$</td>
<td>Initial storage level [GWh]</td>
</tr>
<tr>
<td>$G_{n,t}^{GEN}$</td>
<td>Round-trip storage efficiency [-]</td>
</tr>
<tr>
<td>$C_{n,t}^{GEN}$</td>
<td>Generation cost parameter [(EUR/MWh)/GW]</td>
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<tr>
<td>$\alpha_{n,t}^{GEN}$</td>
<td>Seasonally available generation capacity [GW]</td>
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<tr>
<td>$M_{n,t}^{DSO}$</td>
<td>DSO unit capacity cost per hour of grid use [TEUR/(GW h)]</td>
</tr>
<tr>
<td>$D_{n,t}^{RES}$</td>
<td>Non-prosumage demand [GW]</td>
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<td>$G_{n,t}^{RES}$</td>
<td>Non-prosumage generation potential from RES [GW]</td>
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<tr>
<td>$VOLL$</td>
<td>Value of lost load [EUR/MWh]</td>
</tr>
<tr>
<td>$B_{n,m}$</td>
<td>Network transfer matrix [1/1]</td>
</tr>
<tr>
<td>$f_{l}^{TSO}$</td>
<td>Network susceptance matrix [1/1]</td>
</tr>
<tr>
<td>$E_{n,t}^{TSO}$</td>
<td>Capacities of TSO lines [GW]</td>
</tr>
</tbody>
</table>

**Table A.3**

Primal variables \((\text{var})\) and dual variables \((\text{du})\) of the model.

<table>
<thead>
<tr>
<th>Superset</th>
<th>Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>\text{var}^{PRS}</td>
<td>$pv_{2d_{n,t}}$</td>
<td>Flow from prosumage PV to prosumage demand [GW]</td>
</tr>
<tr>
<td></td>
<td>$s_{2d_{n,t}}$</td>
<td>Flow from prosumage storage to prosumage demand (self-consumption) [GW]</td>
</tr>
<tr>
<td></td>
<td>$m_{2d_{n,t}}$</td>
<td>Flow from market to prosumage demand (self-consumption) [GW]</td>
</tr>
<tr>
<td></td>
<td>$m_{2m_{n,t}}$</td>
<td>Flow from market to prosumage storage (purchase) [GW]</td>
</tr>
<tr>
<td></td>
<td>$s_{2m_{n,t}}$</td>
<td>Flow from prosumage storage to market (sale) [GW]</td>
</tr>
<tr>
<td></td>
<td>$pv_{2m_{n,t}}$</td>
<td>Flow from prosumage PV to prosumage storage [GW]</td>
</tr>
<tr>
<td></td>
<td>$pv_{2m_{n,t}}$</td>
<td>Flow from prosumage PV to market (sale) [GW]</td>
</tr>
<tr>
<td></td>
<td>$\varepsilon_{n,t}^{PRS}$</td>
<td>Energy level of storage [GWh]</td>
</tr>
<tr>
<td></td>
<td>$\ln_{n,t}^{PRS}$</td>
<td>Lost load at prosumage</td>
</tr>
<tr>
<td></td>
<td>$\text{curt}_{n,t}^{PRS}$</td>
<td>Curtailment at prosumage</td>
</tr>
<tr>
<td>\text{var}^{GEN}</td>
<td>$\text{gen}_{n,t}^{DSO}$</td>
<td>Conventional generation [GW]</td>
</tr>
<tr>
<td>\text{var}^{DSO}</td>
<td>$f_{l}^{DSO}$</td>
<td>DSO capacity connected to node $n$ [GW]</td>
</tr>
<tr>
<td>\text{var}^{TSO}</td>
<td>$z_{n}$</td>
<td>Policy variable [-]</td>
</tr>
<tr>
<td></td>
<td>$f_{l}^{TSO}$</td>
<td>Flow at TSO line [GW]</td>
</tr>
<tr>
<td></td>
<td>$im_{n,t}^{TSO}$</td>
<td>Inflow from TSO network [GW]</td>
</tr>
<tr>
<td></td>
<td>$\text{load}_{n,t}^{TSO}$</td>
<td>Lost load at TSO node [GW]</td>
</tr>
</tbody>
</table>

(continued on next page)
Table A.3 (continued)

<table>
<thead>
<tr>
<th>Superset</th>
<th>Name</th>
<th>Description</th>
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<tbody>
<tr>
<td></td>
<td>curtn_t</td>
<td>Curtailment at TNode [GW]</td>
</tr>
<tr>
<td></td>
<td>(\delta_{n,t})</td>
<td>Phase angle [deg]</td>
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<tr>
<td>Duals</td>
<td>(d_a^{PRS})</td>
<td>Shadow price on PV generated electricity [EUR/MWh]</td>
</tr>
<tr>
<td></td>
<td>(\lambda^P_{a,t})</td>
<td>Shadow price on electricity consumed by prosumage [EUR/MWh]</td>
</tr>
<tr>
<td></td>
<td>(\lambda^D_{a,t})</td>
<td>Shadow price on electricity in the storage [EUR/MWh]</td>
</tr>
<tr>
<td></td>
<td>(\lambda^STOR_{a,t})</td>
<td>Shadow price on storage charge [EUR/MW]</td>
</tr>
<tr>
<td></td>
<td>(\lambda^CHARGE_{a,t})</td>
<td>Shadow price on storage discharge [EUR/MW]</td>
</tr>
<tr>
<td></td>
<td>(\lambda^DISCH_{a,t})</td>
<td>Shadow price on storage capacity [EUR/MW]</td>
</tr>
<tr>
<td></td>
<td>(\lambda^G_{a,t})</td>
<td>Shadow price for refilling the storage [EUR/MWh]</td>
</tr>
<tr>
<td></td>
<td>(\lambda^E_{a,t})</td>
<td>Shadow price on generation capacity [EUR/MW]</td>
</tr>
<tr>
<td></td>
<td>(d_a^{GEN})</td>
<td>Shadow price on policy constraint [EUR/MW]</td>
</tr>
<tr>
<td></td>
<td>(d_a^{TSO})</td>
<td>Wholesale electricity price at the TSO node [EUR/MWh]</td>
</tr>
</tbody>
</table>

Appendix B. Players’ constraints

Appendix B.1. Prosumage

\[
0 = pv d_{a,t} + s d_{a,t} + m 2 d_{a,t} + \log^{PRS}_{n,t} D_{n,t}^{PRS} \quad \left(\lambda^P_{n,t}\right)
\]

(B.1)

\[
0 = -pv d_{a,t} - pv2s_{a,t} - pv2m_{a,t} - \text{curt}_{n,t}^{PRS} + \text{g}^{PRS}_{n,t} \quad \left(\lambda^D_{n,t}\right)
\]

(B.2)

\[
0 = \begin{cases} 
-2d_{a,t} + \eta \cdot m 2s_{a,t} - s 2m_{a,t} + \eta \cdot pv2s_{a,t} - e^{PRS}_{a,t} + e^{PRS}_{a,t}, & \text{if } t = 1 \\
-2d_{a,t} + \eta \cdot m 2s_{a,t} - s 2m_{a,t} + \eta \cdot pv2s_{a,t} - e^{PRS}_{a,t} + e^{PRS}_{a,t}, & \text{otherwise}
\end{cases}
\]

\(\lambda^STOR_{n,t}\)

(B.3)

\[
0 \leq e^{PRS}_{n,t} - \bar{P}^{PRS}_{a,n} \quad \left(\lambda^E_{n,t}\right)
\]

(B.4)

\[
0 \leq m 2s_{a,t} + pv 2s_{a,t} - \bar{P}^{PRS}_{a,n} \quad \left(\lambda^{CHARGE}_{n,t}\right)
\]

(B.5)

\[
0 \leq s 2d_{a,t} + s 2m_{a,t} - \bar{P}^{PRS}_{a,n} \quad \left(\lambda^{DISCH}_{n,t}\right)
\]

(B.6)

\[
0 = e^{PRS}_{n,t} - \bar{E}^{PRS}_{n,t} \quad \left(\lambda^G_{n,t}\right)
\]

(B.7)

\[
0 \leq \alpha G^PRS_{n,t} - s 2m_{a,t} - pv2m_{a,t} \quad \left(\lambda^G_{n,t}\right)
\]

(B.8)

Appendix B.2. Generator

\[
0 \leq \delta_{n,t} - \bar{G}^{GEN}_{n,t} \quad \left(\lambda^G_{n,t}\right)
\]

(B.9)

Appendix B.3. DSO

\[
0 \leq f_{n}^{DSO} - m 2d_{a,t} - m 2s_{a,t}
\]

(B.10)

\[
0 \leq f_{n}^{DSO} - \alpha G^{PRS}_{n,t}
\]

(B.11)

Appendix B.4. TSO

\[
0 = -im^{TSO}_{n,t} + m 2d_{a,t} + m 2s_{a,t} - s 2m_{a,t} - pv2m_{a,t} - g_{n,t} + D_{n,t} - G^{RES}_{n,t}
\]

(B.12)

\[
0 = -im^{TSO}_{n,t} + B_{n,t} \Theta_{n,t}
\]

(B.13)

\[
0 = -f^{TSO}_{n,t} + H_{n,t} \Theta_{n,t}
\]

(B.14)
\[0 \leq -f_{TL} + \bar{F}_t \]  
(B.15) 
\[0 \leq f_{TL}^T + \bar{F}_t \]  
(B.16) 
\[0 = \bar{Q}_{dt} \]  
(B.17) 

Appendix C. Data

Figure C.9. Overview on data by state. Top: prosumage household PV generation. Bottom: residual demand (excluding prosumage). Level and distribution of residual demand varies significantly between states. Prosumage households are concentrated on only few states. Data source: own computations on the basis of Open Power System Data (2018); Kunz et al. (2017); Koch et al. (2016).

Table C.4

<table>
<thead>
<tr>
<th></th>
<th>(C_{GEN}^{TL} ) [EUR/MW/GW]</th>
<th>(Q_{GEN}^{TL} ) [GW]</th>
<th>(Q_{PRS}^{TL} )</th>
<th>(P_{PRS}^{TL} )</th>
<th>(E_{PRS}^{TL} )</th>
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<td>Mean</td>
<td>Min</td>
<td>Max</td>
<td>Mean</td>
<td>Min</td>
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<td>20.6</td>
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<td>BE</td>
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<td>47.6</td>
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<td>2.1</td>
<td>1.9</td>
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<td>BW</td>
<td>10.5</td>
<td>9.7</td>
<td>12.1</td>
<td>6.7</td>
<td>5.7</td>
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<tr>
<td>BY</td>
<td>7.9</td>
<td>7.2</td>
<td>9.4</td>
<td>9.8</td>
<td>8.2</td>
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<td>HB</td>
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<td>314.5</td>
<td>356.9</td>
<td>0.1</td>
<td>0.1</td>
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<tr>
<td>HE</td>
<td>35.1</td>
<td>32.9</td>
<td>37.3</td>
<td>2.1</td>
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<tr>
<td>HH</td>
<td>33.6</td>
<td>31.5</td>
<td>35.7</td>
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<td>MV</td>
<td>87.2</td>
<td>81.7</td>
<td>92.7</td>
<td>0.7</td>
<td>0.6</td>
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<tr>
<td>NI</td>
<td>8.8</td>
<td>8.1</td>
<td>9.9</td>
<td>8.3</td>
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<td>NRW</td>
<td>2.8</td>
<td>2.6</td>
<td>3.1</td>
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<td>49.1</td>
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<td>1.9</td>
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<td>SL</td>
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<td>30.1</td>
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<td>1.8</td>
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<td>5.2</td>
<td>4.3</td>
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<td>1.4</td>
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<td>TH</td>
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<td>211.7</td>
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<td>0.4</td>
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<td>Total</td>
<td>72.7</td>
<td>63.9</td>
<td>78.7</td>
<td>5753</td>
<td>2876</td>
</tr>
</tbody>
</table>

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Appendix D. Sensitivity results

Appendix D.1. Daily necessary DSO capacity

Figure D.10. Daily necessary DSO capacity with half storage power capacity ($\sum P_{s}^{PRS} = 1.45 \text{ GW}$). The reference DSO capacity (Max Smart capacity = 2.6 GW) is taken from the results with regular storage capacity.

Figure D.11. Daily necessary DSO capacity with double storage power capacity ($\sum P_{s}^{PRS} = 5.8 \text{ GW}$). The reference DSO capacity (Max Smart capacity = 2.6 GW) is taken from the results with regular storage capacity.
Appendix D.2 Change in system cost

Figure D.12. Sensitivity results on the effect of altering storage power capacities (half, double) on change in prosumage-induced DSO capacity costs as well as operational costs compared to the Smart scenario.

Figure D.13. Sensitivity results on the effect of altering DSO capacity costs (half, double) on change in prosumage-induced DSO capacity costs as well as operational costs compared to the Smart scenario.

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