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Prosumer Impact on Cellular Power Systems

Jens Maiwald *,† and Tino Schütte †

Faculty of Business Administration and Engineering, Zittau/Goerlitz University of Applied Sciences, Theodor-Koerner-Allee 16, 02763 Zittau, Germany; t.schuette@hszg.de
* Correspondence: jens.maiwald@hszg.de; Tel.: +49-3583-612-4634
† These authors contributed equally to this work.

Abstract: This paper explores the impact of an increasing number of prosumers in electricity supply systems and investigates how market mechanisms can mitigate the negative effects. The Regional Energy Market Model simulates a supply system based on cellular structures, employing agent-based modeling to capture individual behaviors and simulate real market dynamics. This study includes various supply scenarios, such as a solely photovoltaic scenario and a technically diversified scenario with biogas-fueled combined heat and power units. For each scenario, fixed and flexible pricing scenarios are simulated to analyze their effects. The findings reveal that systems heavily reliant on photovoltaics experience negative effects at certain points due to seasonal limitations, while technically diversified supply scenarios demonstrate fewer drawbacks. Flexible pricing systems stimulate demand in a manner beneficial to the system, creating regional added value, and contributing to the balance between generation and consumption, depending on the supply scenario. However, the study underscores that economic incentives alone are insufficient for balancing generation and consumption. The results highlight the importance of exploring opportunities through the interplay of economic incentive mechanisms and technical possibilities.

Keywords: cellular approach; agent-based modeling; regional energy markets; simulating behavior; prosumer; power system modeling

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1. Introduction

1.1. Motivation

Once marked by a clear disjuncture between producers and consumers in energy economics, this distinction is now becoming increasingly blurred with the emergence of the phenomenon of prosumers. Prosuming is defined as the (partial) consumption of self-generated electricity, where prosumers embody both producer and consumer roles. Often, prosumers are also the owners of the corresponding generation units. This is particularly evident with low-power generation systems, typically designed to supply single consumers or small consumer groups. Prosumers can either be natural persons or legal entities [1].

Decreasing prices and substantial policy support, such as fixed feed-in tariffs, along with rising electricity market prices, have significantly increased the economic attractiveness of self-supply technologies for many. From a systemic perspective, it is not only about self-supply but also the feed-in of surplus generation into the grid. Thus, the role of prosumers in the energy system has been enlarged while simultaneously facing expectations regarding their contributions to the system [2].

In the overall picture, transitioning from a supply system heavily reliant on conventional energy sources to a more sustainable electricity supply primarily based on renewable energy sources (RESs), prosumers play an important role. Unfortunately, two main problems arise. First, fixed feed-in tariffs are not granted in perpetuity, and prosumer generation units must be profitable at market prices in the long term. Second, an increasing number of prosumers can pose potential challenges to the grid due to the volatility of RESs and the simultaneity of feed-in surpluses, such as voltage and frequency fluctuations, phase mismatches, and supply–demand imbalances [3]. All of these factors could negatively affect the reliability of supply systems.

Numerous papers discuss how technical solutions (e.g., storage systems) or digital aids (e.g., energy management systems) can be used to harmonize volatile generation with rather inflexible demand patterns in different stages of grid levels. There are myriad possibilities, too many to present and discuss in detail within this paper. However, one option has been relatively unexplored so far: economic incentives to flexibilize the demand.

1.2. Theory Development and Hypotheses

Supply systems, especially electricity grids, are currently regulated top-down from the upper to the lower grid levels. However, as the majority of prosumers will operate at the lowest grid level in the future, this control strategy no longer appears suitable given the sheer number of feed-ins. A bottom-up approach needs to be established to enable grid regulation at a lower level. The adoption of so-called microgrids as a solution for the integration of electricity generation from distributed RESs will allow technical problems to be solved in a decentralized fashion, reducing the need for an extremely ramified and complex central coordination [4].

A microgrid can be defined as a group of distributed (renewable) energy sources, energy storage systems, and controllable loads that operate locally as a single controllable entity. They exist in various sizes and can range from simple and small to complex and large networks [3–6]. Due to the energy storage capabilities, a microgrid can operate in grid-connected or islanded modes with a seamless transition between the two modes [6].

Optimally designed, microgrids offer significant benefits, including enhanced security of supply, lower electricity prices, the integration of excess RES generation into the microgrid, and even economic growth in rural areas [7]. However, achieving optimal energy management in microgrids is a challenging task, particularly in terms of efficiently utilizing RESs and energy storage systems while considering the uncertainty associated with load demand and renewable power generation [7].

In the context of this paper's focus, the fundamental contribution of financial incentives to adapting inflexible demand to volatile generation is examined. To sufficiently broaden the potential scope of the investigation, considering a microgrid in the sense of a district solution or smaller does not appear meaningful. The scope should be larger. Therefore, the analysis centers on a regional electricity market within a local supply system. Recently proposed regional market designs, as tested in [8], were found to be financially unattractive for prosumers within the current regulatory framework in the context of the German market. However, as the systematic review in [9] on different time-of-use electricity tariffs shows, there is a definite demand for flexible price tariffs. As demonstrated by [10–12], price signals can trigger reactions and adjustments in electricity demand among different consumer groups, impacting the market. Taking all this into account, a counterfactual market scenario (see Section 2.1) is set up to test the following hypotheses:

Hypothesis 1. *There is a limit to the increase in demand for green electricity, as both the willingness to pay and consumption have finite capacities and cannot perpetually grow.*

It is inherent that consumers' willingness to pay (WTP) and consumption are finite capacities. The WTP varies among individuals based on personal preferences and budget constraints. Likewise, electricity consumption is constrained by actual physical demand and technical limitations, restricting potential increases. Consequently, there is a natural constraint on the growth of market demand for green electricity.

Hypothesis 2. *An increase in the demand for green electricity is hypothesized to result in a reduction in the effort required to achieve an equilibrium between generation and consumption in the market area.*

An increase in demand for green electricity is incentivized by decreasing prices resulting from high feed-in volumes of green electricity. This will reduce surpluses in times of overcapacities. It is also expected that learning effects will occur as a result of successful transactions. Consumers are likely to become more conscious of their energy consumption patterns. This heightened awareness could lead consumers to adjust their electricity usage based on the availability of green electricity. Consequently, the systemic effort required to balance generation and consumption in the market area may decrease.

Hypothesis 3. *As the number of prosumers increases, there will be a positive effect on the supply of green electricity at first. This positive effect turns into a negative effect at a certain point when supply exceeds demand.*

An increasing number of prosumers implies a higher generation of green electricity available during periods of overcapacity in the market, thereby increasing the overall supply. Additionally, as prosumers (partially) consume their self-generated electricity, it reduces their impact on the demand side of the market, consequently increasing the available supply for pure demanders. However, as outlined in Hypothesis 1, the market demand is finite, establishing a saturation volume for supply. With the growing number of suppliers, reaching this saturation point becomes more likely. This effect is further intensified by the earlier mentioned fact: Prosumers do not solely act as consumers; the fewer consumers participating in the market, the smaller the saturation volume.

Hypothesis 4. *A supply system relying solely on solar photovoltaic prosumers will likely experience higher positive effects only during summer but only up to a certain point.*

At first glance, this hypothesis may not appear particularly bold, but it is grounded in several considerations. Photovoltaic (PV) is a highly seasonal and weather-dependent generation technology. During the winter months, the minimal trading volume of green electricity from PV is anticipated in the market. In transitional months, prosumers are likely to consume a substantial part of their self-generated electricity, also resulting in a low trading volume in the market. In summer, midday peaks will lead to significant overcapacity, surpassing the saturation volume of the market. An increasing number of PV prosumers will not counterbalance the negative effects in winter but will amplify the positive effects in summer until they become negative (see Hypotheses 1 and 3). Diversifying generation technologies could partially alleviate these effects by implementing technologies in the system capable of generating green electricity in the cold season and remaining inactive during summer, such as combined heat and power (CHP) units.

2. Materials and Methods

2.1. Structure of the Study

This study's investigations are based on the Regional Energy Market Model (REMM), a model designed to map actor behavior in regional energy markets and investigate the behavioral effects. Only some of the functions implemented in the REMM are required in this paper. Therefore, a complete description of the model will be omitted now and in the following paragraphs and only the part of the required implementations will be discussed. A detailed REMM description can be found in [13].

The REMM was developed in NetLogo (Version 6.2.2, see Appendix A) as a bottom-up approach for integral load management, investigating short-term scenarios in decentralized energy markets. While the REMM can simulate various supply scenarios, this paper focuses on local supply systems. This assumption aligns with [9], where it is proven that there is significant potential for covering energy demand based on renewable energies, especially in smaller communities. Moreover, ref. [9] demonstrates that the transformation of urban energy systems toward the use of local and sustainable energy resources can be the preferred alternative. However, as [9] primarily inspects these issues from a systems perspective using top-down equilibrium models, this paper's model primarily focuses on the consumer groups themselves, utilizing REMM's bottom-up approach.

An exemplary scenario was set up, comparable to the supply system of a small center town in Germany with 26,000 inhabitants. The observed supply system is, therefore, a local distribution grid with its typical entities. This includes private households and small to medium-sized companies from the trade, commerce, and service sectors, as well as the local utility company (LUC) acting as the grid operator. Each individual entity is represented by an agent in the model. It should be noted that the exclusion of companies from the industrial sector in this study was a deliberate choice. This decision is rooted in the fact that large consumers are typically connected to higher grid levels than the distribution grid, which would contradict the microgrid focus of these investigations. Additionally, the inclusion of industrial companies could significantly influence the model results, given their substantial leverage in demand volume compared to individual households or small businesses.

The REMM inherently possesses the capability to represent microgrids. As mentioned earlier, the model adopts a bottom-up approach, known as the cellular approach (CA; for further details on CA, refer to Section 2.2). Given that the REMM is an energy economics model, it incorporates the CA from an economic standpoint. Each model entity is tasked with achieving the equilibrium between generation and consumption independently. In cases where this equilibrium is unattainable, entities can actively seek suitable trading partners within the regional market. This regional market is not treated as an isolated market but as an integrated unit in the wholesale market. Therefore, if no suitable regional trading partner is found, wholesale trading becomes an alternative.

As the focus of this paper is not on optimizing the overall system outcome but rather on simulating emerging phenomena due to certain behaviors of market participants, agent-based modeling (ABM; for further details, refer to Sections 2.3 and 2.4) was the method of choice. Alongside the energy economic model, the REMM includes a behavioral model grounded in ABM. This behavioral model is inspired by the analysis presented in [12], specifically investigating environmentally conscious decisions related to the purchase of green electricity by residential customers, with a focus on customer preferences. This paper adopts and extends this approach to encompass the preference for regionality, applying it not only to one specific consumer group but to all consumer groups within the supply system.

To assess the presented hypotheses, the analyses in the REMM are structured in the following steps:

Step 1: A base scenario is calculated, serving as the starting point for all subsequent analyses. This scenario includes a fixed price system and assumes the approximated current expansion level of 10% PV for households and businesses [14].

Step 2: According to the base scenario, additional scenarios with expansion levels of 20%, 30%, and 50% PV are calculated. The 50% scenario represents an extreme case assumption. This step will deliver the first insights for the assessment of Hypotheses 3 and 4.

Step 3: Scenarios with a PV expansion of 10%, 20%, 30%, and 50% are simulated, each incorporating a flexible pricing system in the REMM. The design of the flexible pricing system is described in Section 3.1.4. The results are compared with those from steps 1 and 2 in order to assess Hypotheses 1 and 2. Moreover, new insights for Hypothesis 3 are gained throughout this step.

Step 4: To conclusively address Hypotheses 3 and 4, fixed pricing system (steps 1 and 2) and flexible pricing system (step 3) scenarios are calculated, incorporating additional CHP expansion from 5%, 10%, 15%, and 25%. It is presumed that the expansion of CHP occurs at a slower rate than that of PV. This assumption is grounded in the more challenging installation process associated with CHP systems compared to PV.

2.2. Cellular Approach

The CA, as a bottom-up approach for energy system planning, focuses on achieving equilibrium between energy generation and consumption at the lowest possible level.

Therefore, energy cells are at the center of the considerations. Each cell has energy-supplying converters, energy-dissipating converters, and one or more local storage units. In simple terms, a cell is defined as being able to generate, consume, and store energy. The goal of every cell is to balance generation and consumption itself. In the event a cell is unable to achieve this equilibrium, it connects with one or more other unbalanced cells. Several cells at one level can be grouped and reflected at the next higher level as a single cell, treated according to the same basic principle (see Figure 1) [15].

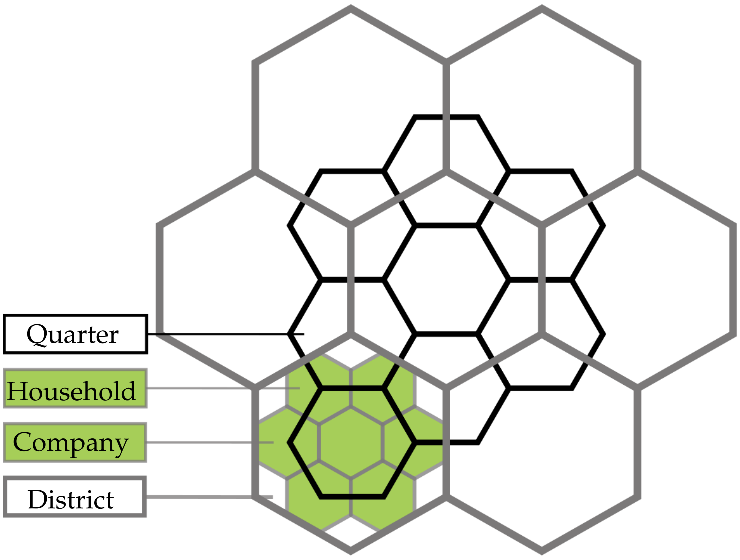

Figure 1. Energy cells (authors' own compilation based on [16]).

Although the basic concept of the CA was not new (see e.g., [17]), the first concrete feasibility study was presented in [15]. However, the adoption of the CA in this paper differs slightly from that study. In its fundamental approach, the CA assumes that cells follow a multi-modal approach, considering various types of energy, such as electricity and heat. As mentioned, this paper's focus is solely on the electricity sector. Additionally, the CA considers energy flows in their physical sense, while this paper's model balances energy quantities, focusing on the economic perspective. Moreover, the 2015 study raises the question of how an energy system would need to be fundamentally structured to implement the cellular principle (Greenfield Approach). In this paper, the CA is applied to the structures of an existing local supply system.

In its key finding, ref. [15] states that the cellular approach (CA) is generally feasible. However, it emphasizes the necessity to expand decentralized structures for future energy supply while simultaneously underlining the importance of interregional energy balancing.

2.3. Agent-Based Modeling

ABM allows for the depiction and investigation of individual interactions between agents, between agents and other factors such as time and space, and the resulting effects on the overall system [18]. Thus, interdependencies between the microscopic and macroscopic levels can be examined. On the microscopic level, agents make decisions based on the variables and rules applicable to them at the current point in time. In turn, on the superordinate, i.e., macroscopic, level, overall systemic phenomena occur without being solely attributable to isolated properties and decisions of individual agents [12,19–21].

2.4. Agent-Based Modeling in Energy Economics

ABM in economics offers a framework for the computational study of economic processes modeled as dynamic systems of interacting agents [22,23]. Events that occur in reality between customers and suppliers during the negotiation and trading processes are often greatly simplified or even neglected in other types of models. Even though the methodological approach is more demanding, ABM allows for the consideration of aspects such as asymmetric information, strategic interaction, expectation formation, transaction costs, external effects, multiple equilibria, and dynamics outside the equilibrium [22]. Within the market, agents communicate with each other and react to market signals by adjusting their individual strategies to different market events. These strategy adjustments (learning effects) are based on decision rules that are implemented for each agent. In such models, a market consists of repeating bidding rounds, with the possibility of strategy adjustments between each round [24,25].

Compared to other markets, special conditions apply to electricity markets, which result primarily from technical restrictions and characteristics of electricity as a commodity. In particular, the limited storability of electricity and its transmission through the grid is based on physical laws rather than economic rules [24,26]. Therefore, the trading of electricity is a balance sheet trade, as the physical fulfillment of the transaction is separate from the actual trade. In addition, the public grid represents a natural monopoly for which usage rights must be acquired and paid for in the form of grid fees.

Models in energy economics therefore usually comprise two levels to adequately depict this complexity: a technical and an economic level. In the case of ABM, sometimes even a socio-economic level is included. While the technical level contains various supply technologies and simulates the operation of the energy system, the market participants (agents) act on the socio-economic level, sometimes changing the structure of the technical system and concluding contracts for energy supplies [27]. Pure economic or financial models, on the other hand, can only poorly explain what happens in the electricity market [26].

3. The Regional Energy Market Model

3.1. Model Theory

3.1.1. Demand Side

Agents representing private households are characterized by the (dynamic) standard load profile H0 and are, therefore, referred to as Residential with Standard Load Profile (RSL) within the REMM. Trade, commerce, and service companies are characterized by the standard load profile G0 and are referred to as Business with Standard Load Profile (BSL). Both profiles were published by the German Electricity Association (see Appendix A). Since they are standardized to an annual consumption of 1000 kWh, each hourly value of these profiles has to be multiplied by a scale factor to make them usable in the model. The scale factor assigned to each agent was randomly chosen from a given domain during the model setup (see Table 1). Constraints ensure that the REMM accurately depicts the overall distribution of households or business sizes in Germany and thus their overall electricity consumption (see [13]). In total, the REMM comprised 15,407 RSL and 1638 BSL agents.

Table 1. Scale factor domains.

	Residential	**Business**
Scale factor	$\in [1;5]$	$\in [1;12]$

3.1.2. Supply Side

Given the focus on cellular structures and prosumers in this observation, it is assumed that demand-side agents operate all generation units. In line with the steps for assessing hypotheses (see Section 2.1), PV and CHP units are implemented in the model. Generation from solar PV accounts for the variable nature of the availability of RESs. CHP units, fueled with biogas, represent characteristics of controllable renewable generation.

The model randomly selects agents to become prosumers. Each prosumer can operate either only one type of generation unit or both combined. The individual generation capacities of these units are aligned with the annual electricity consumption of the operating agents, based on specific criteria (see [13]). Generation from PV relies heavily on solar radiation. CHP units operate in a heat-controlled mode, and therefore, their performance depends on the temperature. To accurately depict these generation patterns, a database is linked to the model, providing authentic local weather data for wind speed, solar radiation, and temperature. These data were obtained from the Test Reference Years of the German Meteorological Service (see Appendix A).

Each prosumer prefers to consume their self-generated electricity to cover their consumption. During periods of overcapacities, that means generation exceeds consumption, and prosumers sell the surplus electricity in the regional market. Conversely, if generation is insufficient to cover consumption, prosumers will purchase the additional electricity they need from the market.

3.1.3. Local Utility Company

In the model's observations, the focus is on the effects of prosumer and consumer behavior. Therefore, the LUC is modeled to act passively. In this context, 'passive' implies that the LUC is modeled without any consumption, demand, or supply. Moreover, the LUC operates without the intention of making a profit. However, given the existence of a local market and supply system, a system operator is essential. In the REMM, the LUC serves as this enabler, maintaining the overall system, responding to market conditions, and undertaking market clearing. Additionally, the LUC serves as the connector between the regional and interregional wholesale markets, selling or purchasing electricity based on regional over- or undercapacities, respectively.

Figure 2 gives an overview of the REMM's structure and interdependencies while summarizing Sections 3.1.1–3.1.3.

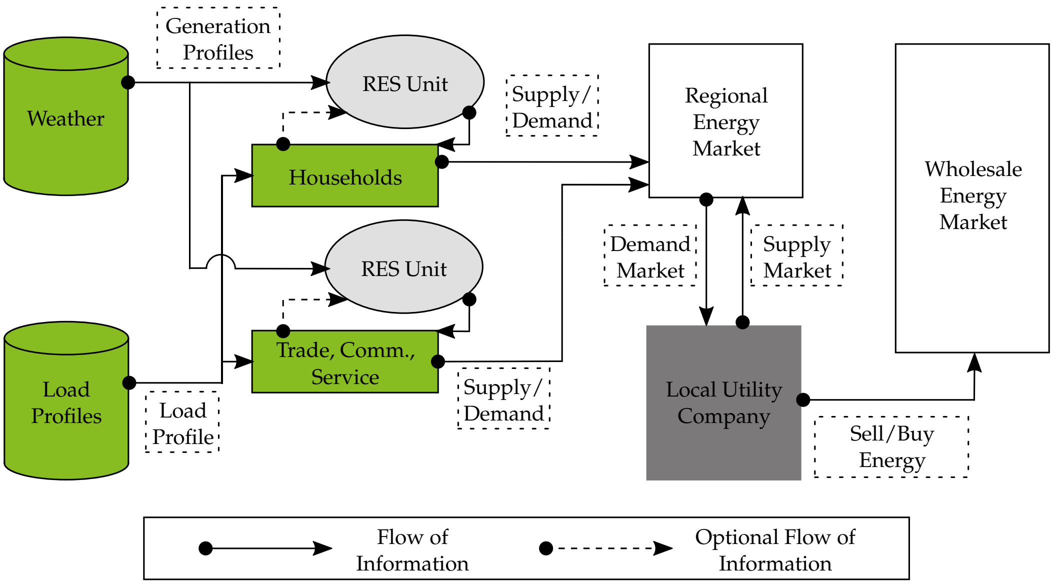

Figure 2. Structure of the REMM.

3.1.4. Market, Products, and Pricing

The REMM was developed to map the effects of preference-based consumer behavior (see Section 3.1.5). Consequently, it only makes sense to structure the product range in such a way that these preferences are reflected. The market was therefore divided into four different products incorporating a modular pricing system. The differentiation is based on the energy source from which the electricity is generated and the location where the electricity is generated. Thus, there are green and grey products, each with regional and interregional background (see Table 2).

It is worth noting that, at first glance, it seems obsolete to include a grey regional product if there is no local conventional production in the system. However, as will become clear later in the paper, this is nevertheless appropriate.

Table 2. Electricity products and price components in REMM.

	Origin	
Source	I—Green & Regional ($p_{base} + p_{green} + p_{regio}$)	II—Green & Interregional ($p_{base} + p_{green} + p_{trans}$)
	III—Grey & Regional ($p_{base} + p_{regio}$)	IV—Grey & Interregional ($p_{base} + p_{trans}$)

3.1.5. Decision Making

Agent behavior in the REMM is influenced by three properties: (I) environmental awareness, (II) regional awareness, and (III) cost sensitivity (see Table 3). Environmental awareness describes the individual preference for green energy sources. Regional awareness represents the preference for electricity generated in a local context. For both properties, a value close to one indicates a high preference, while a value close to zero indicates a low preference. Cost sensitivity describes the individual assessment of higher costs, which is directly dependent on the income for RSL or earnings for BSL. A value close to one indicates a high sensitivity to costs, while a value close to zero indicates a low sensitivity, meaning that these agents would be willing to pay higher prices.

Table 3. Consumer preference domains.

Environmental Awareness	Regional Awareness	Cost Sensitivity
$e \in \;]0;1]$	$l \in \;]0;1]$	$c \in \;]0;1]$

At each time step, all purchasing entities make a new decision regarding their preferred electricity product. This generally involves a two-stage decision process. These agents compare the grey and green products, as well as the regional and interregional products, by calculating their utility values U. Ultimately, the product is chosen based on the one that offers the highest personal value.

3.2. Model Implementation

3.2.1. Economic Model

The REMM characterizes entities by two main attributes, consumption *con* and demand *dem*. Consumption describes the total electricity need of an agent i per time step t, while demand represents the electricity purchase from the grid. The demand of a prosumer agent depends on his generation *gen* (see Equation (1)). Since the generation of a consumer agent is 0, it follows that $dem = con$.

$$dem_{i,t} = con_{i,t} - gen_{i,t} \quad (i = 1 \text{ to } n,\ t = 1 \text{ to } 8760) \tag{1}$$

The sales volume *vol* that prosumers offer on the market logically depends on their personal difference between consumption and generation. Since consumers are not able to generate electricity, the sales volume is therefore 0.

$$vol_{i,t} = \begin{cases} 0 & : \ gen_{i,t} \leq con_{i,t} \\ gen_{i,t} - con_{i,t} & : \ gen_{i,t} > con_{i,t} \end{cases} \tag{2}$$

The electricity price p_{el} results as the sum of three components: (I) source of electricity; (II) grid fee; and (III) taxes, levies, and apportionments. Since the third component is incurred for each product, it is considered as 0 and, thus, not taken into account in further analysis.

$$p_{el} = p_{source} + p_{grid} + p_{tax} \tag{3}$$

Buyers purchasing grey electricity have to pay a base price p_{base}. For those choosing green electricity, an additional price premium p_{green} is applied. This premium serves as an incentive for supporting renewable energy sources, resembling past initiatives such as the levy under the German Renewable Energies Act.

$$p_{source} = \begin{cases} p_{base} & : \textit{Grey product} \\ p_{base} + p_{green} & : \textit{Green product} \end{cases} \quad (4)$$

All prosumer entities selling self-generated electricity are considered producers offering regional electricity. Conversely, electricity generated outside the observed area is classified as interregional. In the REMM, regional purchases can incur a different grid fee than interregional purchases.

$$p_{grid} = \begin{cases} p_{reg} & : \textit{Regional Purchase} \\ p_{trans} & : \textit{Interregional Purchase} \end{cases} \quad (5)$$

The regional market is highly volatile. Consequently, situations can arise where parts of the preference-driven demand cannot be met. In REMM, the LUC is responsible for performing the market clearing. Situations characterized by a regional oversupply are not crucial for the simulation, given the assumption that leftover electricity could be sold at the wholesale market at any time. It is also not critical if there is no sales volume for green electricity in the market. However, situations with undersupply, or in this case, a shortage of sales volume compared to the demand for green regional electricity, can become challenging. A decision has to be made regarding which agents get served and who has to switch to another product, along with the criteria for making this decision.

In this special case, the decision on which agent to serve is based on their WTP, derived from utility functions described in Section 3.2.2. The green regional market section is cleared first. All applying agents are listed based on their WTP for green electricity, with those having a higher WTP served before those with a lower WTP. Agents who cannot be served are then forced to switch to an alternative product. The second step involves clearing the grey regional market section. Since there is no regional conventional generation discussed in this paper, and, consequently, sales volume is 0, it is mandatory to take this step due to later model procedures. All agents not served in the first two clearing steps, as well as those who initially decided to purchase interregional electricity, are served in the third step. For more information on determining the WTP and switching to alternative products, refer to [13].

3.2.2. Behavioral Model

Similar to the approach in [12], purchasing agents calculate the utility value U by comparing an intrinsic value u_{intr} with the negative value of (higher) costs u_{cost} in a two-stage decision process. The first stage is the decision on whether to choose a green or grey electricity product. The second stage involves deciding between purchasing a regional or interregional product. It should be noted that even if there is no consideration of regional conventional energy generation in this paper, it is still essential to allow all agents to decide on this product. This is necessary due to the interdependencies with alternative products required to calculate the utility values. Moreover, it is necessary within the market clearing process of the REMM.

Decision I: Calculating the intrinsic value for green electricity, it is assumed that one unit of the additional price premium p_{green} for electricity from RESs can be converted into exactly one unit of an abstract personal good. This abstract personal good can be interpreted as well-being or moral satisfaction. The intrinsic value is derived from the agent's environmental awareness e combined with its price sensitivity c and the amount of p_{green}. Consequently, the intrinsic value for the purchase of grey electricity is 0.

$$u_{intr,i,t} = \begin{cases} 0 & : \; Grey \\ e_i \cdot \sqrt{p_{green,t}} \cdot c_i & : \; Green \end{cases} \tag{6}$$

This intrinsic value is compared with the (negative) effect of higher costs caused by the extra mark-up for green electricity. The effect is determined by the agent's price sensitivity c and the amount of the price components p.

$$u_{cost,i,t} = \begin{cases} c_i^2 \cdot p_{base,t} & : \; Grey \\ c_i^2 \cdot (p_{base,t} + p_{green,t}) & : \; Green \end{cases} \tag{7}$$

Hence, the overall utility functions for the purchase of green and grey electricity are formed as follows:

$$U_{grey,i,t} = 0 - c_i^2 \cdot p_{base,t} \tag{8}$$

$$U_{green,i,t} = e_i \cdot \sqrt{p_{green,t}} \cdot c_i - c_i^2 \cdot (p_{base,t} + p_{green,t}) \tag{9}$$

Decision II: This stage's logic follows the approach from stage I. Here, it is assumed that an intrinsic value exists for the purchase of electricity generated in a regional context. The intrinsic value for interregional purchase is consequently 0.

$$u_{intr,i,t} = \begin{cases} l_i^2 \cdot \sqrt{p_{reg,t}} \cdot c_i & : \; Regional\ purchase \\ 0 & : \; Interregional\ purchase \end{cases} \tag{10}$$

The utility value for costs is determined analogously to the approach in stage I, taking into account the different price components for regional and interregional purchases.

$$u_{cost,i,t} = \begin{cases} c_i^2 \cdot p_{reg,t} & : \; Regional\ purchase \\ c_i^2 \cdot p_{trans,t} & : \; Interregional\ purchase \end{cases} \tag{11}$$

Combining both, the overall utility functions for regional and interregional purchases appear as follows:

$$U_{reg,i,t} = l_i^2 \cdot \sqrt{p_{reg,t}} \cdot c_i - c_i^2 \cdot p_{reg,t} \tag{12}$$

$$U_{inter,i,t} = 0 - c_i^2 \cdot p_{trans,t} \tag{13}$$

4. Results

4.1. Scenario Framework

The following scenario framework was created to implement the steps outlined in Section 2.1. Table 4 provides a summary of the different expansion stages to be simulated. Initially, a supply system equipped solely with PV units was simulated. After that, this PV system underwent further expansion to include CHP.

Table 4. Expansion stages for RESs.

Path	(a)	(b)	(c)	(d)
PV	10%	20%	30%	50%
PV & CHP	10%; 5%	20%; 10%	30%; 15%	50%; 25%

In addition, different price scenarios were simulated for these RES expansion stages. Table 5 provides an overview of the details. The price assumptions were derived from the average electricity prices for households in Germany in 2015, which also served as the reference year for the weather data and distribution variables for RSL and BSL agents [28]. The main difference between them was that the price component for green electricity in the flexible price scenario changed based on the regional utilization of the RES units; the higher the regional generation, the more affordable the price component, and vice versa. Finally, it was examined whether an additional reduction in the price component of the regional grid fee compared to the grid fee for interregional purchases had an additional effect.

Table 5. Price components for different scenarios.

	Fix	Flex	Flex & Regio
p_{base}	7.5 ct/kWh	7.5 ct/kWh	7.5 ct/kWh
p_{green}	6.5 ct/kWh	[2; 6.5] ct/kWh	[2; 6.5] ct/kWh
p_{regio}	7.5 ct/kWh	7.5 ct/kWh	6 ct/kWh
p_{trans}	7.5 ct/kWh	7.5 ct/kWh	7.5 ct/kWh

In order to account for the randomness inherent in the REMM, arising from distributions of agent properties, five model runs were calculated for each scenario and summarized at the end as an arithmetic mean.

4.2. Evaluation Framework

Essentially, this investigation focuses on two key issues and their outcomes: (I) the influence of RES expansion on generation and market sales volume; and (II) shifts in demand arising from the flexibility of electricity prices. Therefore, all scenarios, including PV (a)–(d) and PV and CHP (a)–(d), underwent simulation within both the fixed price and flex price systems, followed by subsequent analysis.

Since the total consumption in the system remains rather constant due to the fixed number of agents, the focus of the analyses is on demand. However, it is important to note that a change in demand does not equate to an adjustment in consumption. Instead, it signifies a shift from an alternative product to a green regional product, while overall consumption remains unchanged.

Two cases were of particular interest for the analyses: (I) the scenario where the sales volume for green regional electricity exceeded the demand for this product, implying that regional value creation could be realized with an increase in demand, and (II) the situation where the sales volume surpassed the total regional consumer consumption, indicating that an increase in consumption could result in regional value creation.

Therefore, the initial focus is on examining the ordered residual load curve of the supply system for each scenario (a)–(d). This involves subtracting the amount of generated RES electricity from the amount of consumption in each hour, enabling to draw conclusions regarding the duration of under- or overcapacities within the system.

The focus then shifts to the actual demand, specifically examining the changes that occur due to flexible prices and how the demand aligns with the sales volume during the period under review. For the sake of visualization, the analysis cannot be conducted individually for each hour. Therefore, a quantitative evaluation is performed in relation to the months of the year under review to present an overview of flexibilization effects and seasonal influences.

Finally, an analysis variable specifically developed for the REMM is introduced: the residual sales volume of the market. This variable is based on the logic of the residual load of the supply system, which primarily focuses on load (consumption or demand). However, for market evaluation in the REMM, the focus is on regional supply, specifically the sales volume. Consequently, the logic is applied in the opposite direction, where the actual demand is subtracted from the sales volume for green electricity. This approach allows to draw conclusions about when the market is oversupplied or undersupplied and to assess the effects of flexibilization.

4.3. Scenario Results: Solely PV

Figure 3 displays the ordered residual load curve for the period under review across the different scenarios (a)–(d) in relation to the entire supply system. It is noticeable that scenario (a) experiences no regional oversupply at any time. Hours with overcapacity begin to occur from scenario (b). Scenarios (c) and (d), with around 1000 and 1700 h, respectively, exhibit a large number of hours with sometimes immensely high overcapacities. In combination with an undercapacity of around 4000 h, these scenarios are not recommended from a systemic perspective.

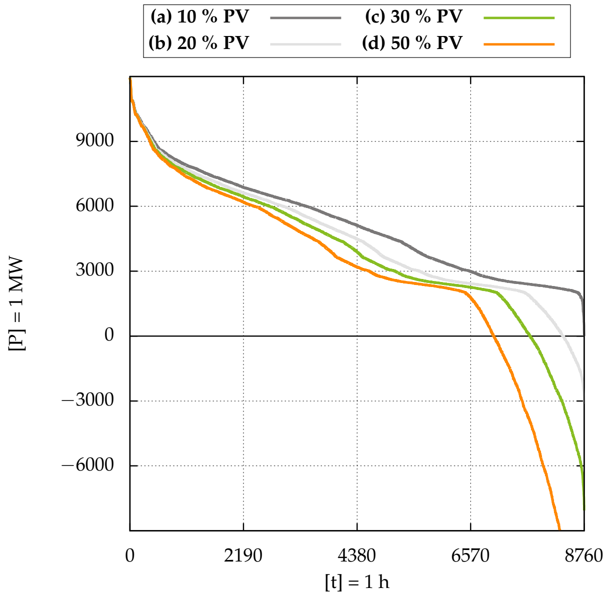

Figure 3. Ordered residual load profile (region) of the supply system over one year for different PV expansion stages (a)–(d) .

Figures 4 and 5 illustrate the variations in demand for green regional electricity in the regional market in the fixed price and flex price scenario, aggregated over one month. Figure 4 depicts the PV expansion scenarios (a) and (b), and Figure 5 shows scenarios (c) and (d). Two notable trends emerge: (I) Across all scenarios, demand under flexible pricing consistently surpasses that under fixed prices; and (II) with the growth of RES expansion in the system, the overall market demand decreases. This is primarily driven by the increasing numbers of prosumers, who participate less frequently as 'demanders' in the market compared to pure consumers.

Figures 6 and 7 extend the findings from Figures 4 and 5, including the available sales volume for green regional electricity in the regional market. Figure 6 depicts PV expansion scenarios (a) and (b), and Figure 7 shows scenarios (c) and (d). It should be noted that these figures only show aggregated quantities and do not display hourly analyses. In scenario (a), supply and fixed price demand balance relatively well from May to August. At this point, the increase in demand due to flexibilization has seemingly no effect, as there is not enough left-over sales volume to meet the increased demand. However, during months with limited solar radiation, the generation capacity falls short of covering demand. Scenario (b) extends the period for meeting demand to April to September but results in significant oversupply during summer months, in some cases by a factor of up to 2, even in the flex price scenario. Scenarios (c) and (d) show minimal improvements in meeting demand and, more critically, lead to a significant oversupply during summer months by a factor of 3 in (c) and a factor of 5 in (d).

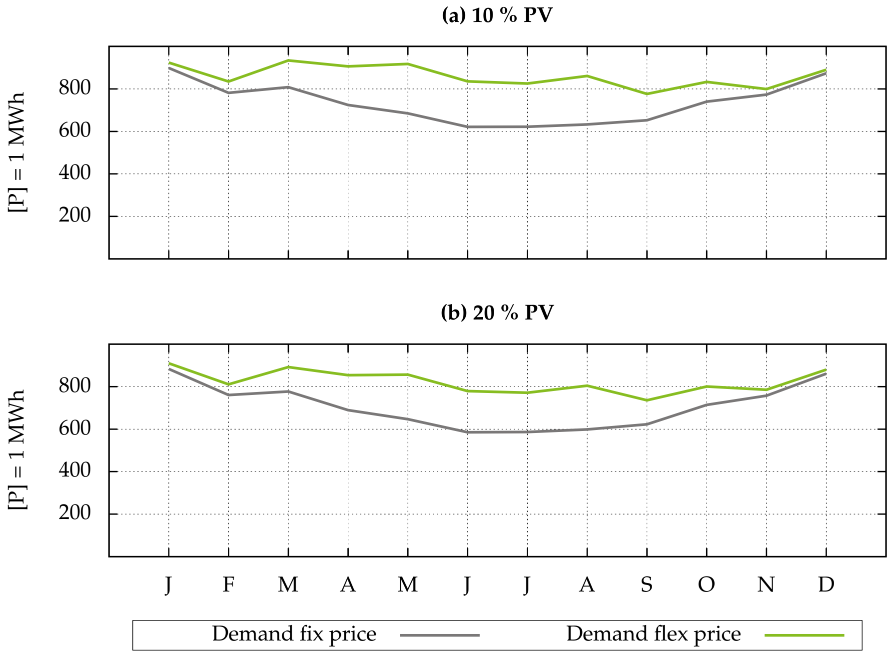

Figure 4. Total demand per month for regional green electricity in fixed and flex price systems over one year for PV expansion stages (a) 10% PV and (b) 20% PV.

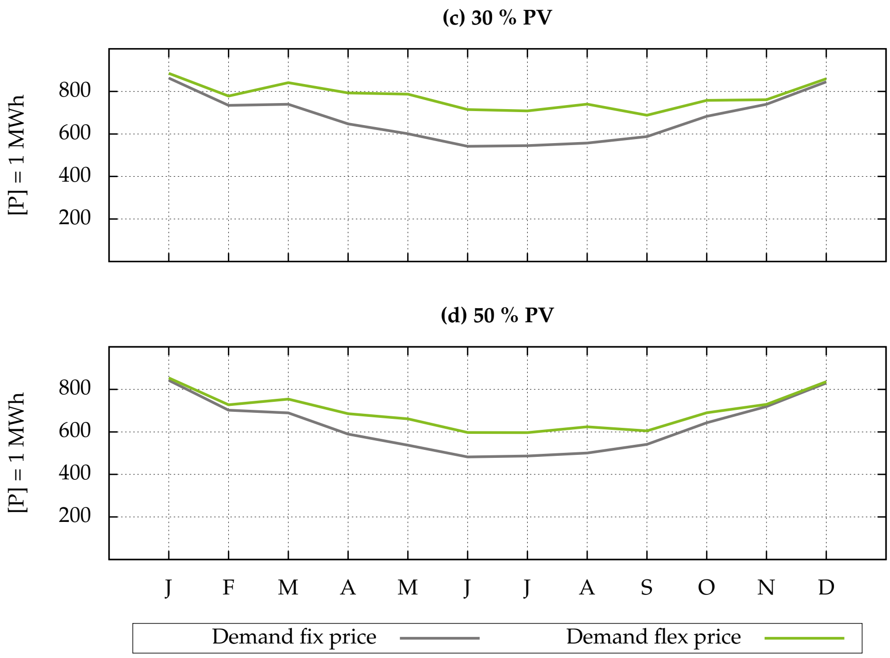

Figure 5. Total demand per month for regional green electricity in fixed and flex price systems over one year for PV expansion stages (c) 30% PV and (d) 50% PV.

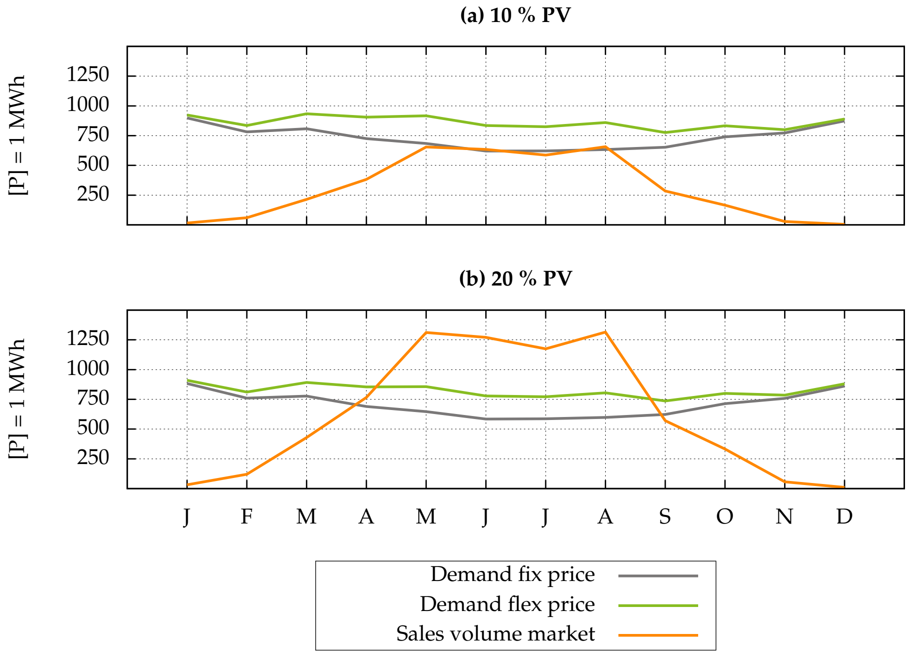

Figure 6. Relation between total demand in fixed and flex price scenarios and total sales volume per month for regional green electricity over one year for PV expansion stages (a) 10% PV and (b) 20% PV.

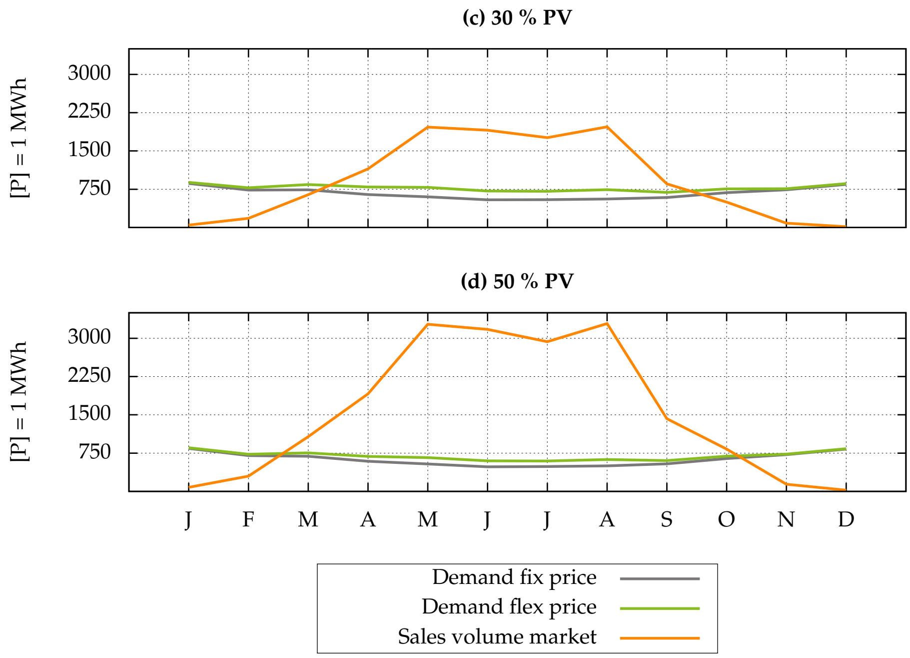

Figure 7. Relation between total demand in fixed and flex price scenarios and total sales volume per month for regional green electricity over one year for PV expansion stages (c) 30% PV and (d) 50% PV.

Figures 8 and 9 display the residual sales volumes for the regional market under both the fixed price and flex price systems. Figure 8 displays the PV expansion scenarios (a) and (b), and Figure 9 shows scenarios (c) and (d). While the quantitative analysis in Figure 6 initially suggests that no effects can be harnessed through flexibilization under scenario (a), this specific analysis reveals that these effects do exist. It indicates that regionally generated electricity could be marketed within the region. Similar effects are observed for scenario (b), although the impact appears limited due to the constraint that demand cannot be increased beyond an upper limit and the growing number of prosumers. In scenarios (c) and (d), these constraints seem to completely block the positive effects of flexibilization.

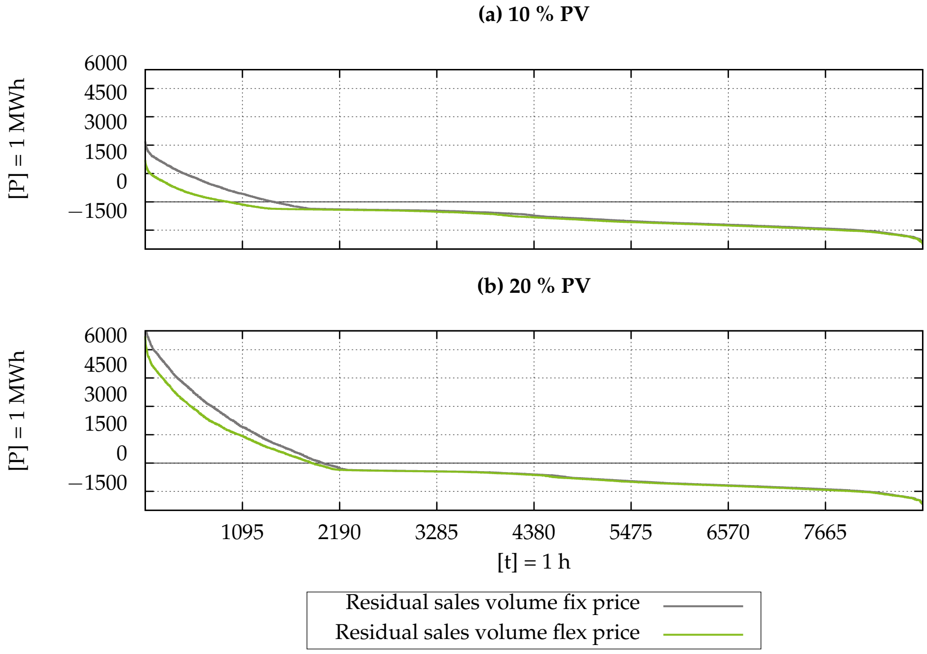

Figure 8. Ordered residual sales volume in fixed and flex price scenarios over one year for PV expansion stages (a) 10% PV and (b) 20% PV.

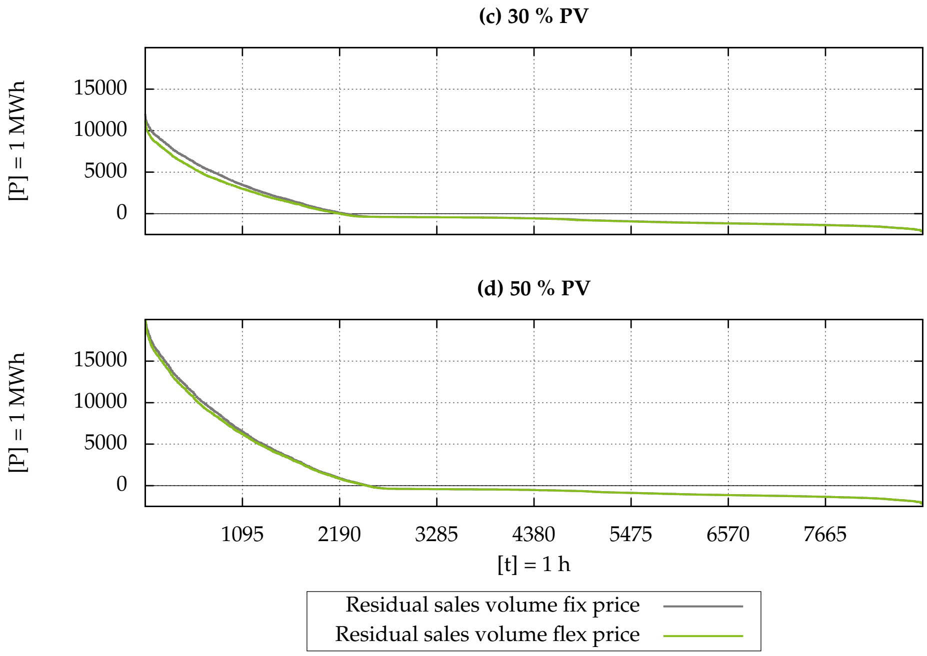

Figure 9. Ordered residual sales volume in fixed and flex price scenarios over one year for PV expansion stages (c) 30% PV and (d) 50% PV.

4.4. Scenario Results: PV and CHP

Figure 10 illustrates the ordered residual load curve for the observed period across scenarios (a)–(d) in relation to the entire supply system. Similar to Figure 3, scenario (a) experiences no regional oversupply at any time. Also, hours with overcapacity begin to occur in scenario (b). Scenarios (c) and (d) exhibit significantly higher numbers of hours with overcapacities, with 1300 and 3400 h, respectively, compared to the solely PV scenario. In the solely PV expansion scenario, none of the scenarios (a)–(d) has undercapacities by less than 6000 MW in the first 2000 h of the graph. In the PV and CHP expansion scenarios, only scenario (a) exhibits this characteristic. This indicates that in this expansion scenario, generation matches consumption more closely than in the solely PV scenario.

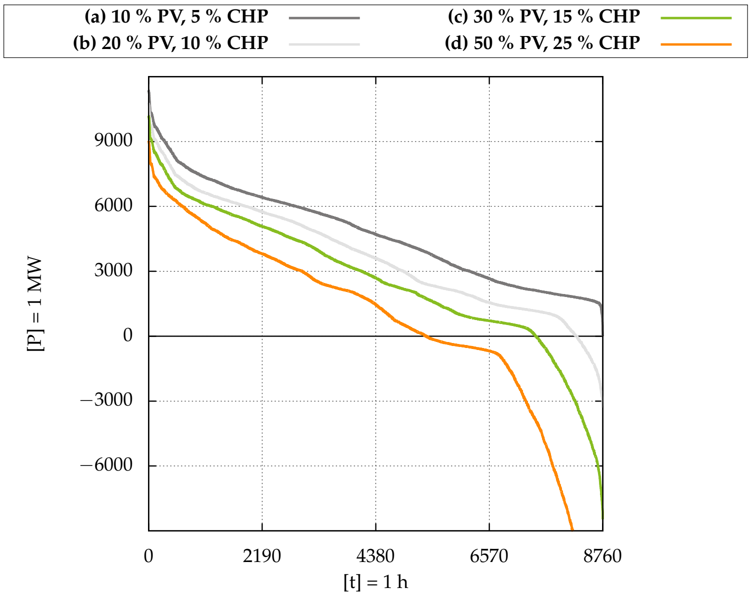

Figure 10. Ordered residual load profile (region) of the supply system over one year for different PV and CHP expansion stages (a)–(d).

Figures 11 and 12 illustrate the variations in demand for green regional electricity in the regional market in the fixed price and flex price scenario, aggregated over one month. Figure 11 depicts the expansion scenarios (a) and (b), and Figure 12 shows scenarios (c) and (d). The two notable trends observed in the solely PV scenario (see Figures 4 and 5) can be observed here as well: (I) Demand under flexible pricing consistently surpasses that under fixed prices in all scenarios, and (II) with the growth of RES expansion in the system, the overall market demand decreases, here, of course, in a more drastic manner than in the solely PV scenario due to the higher number of prosumers. However, a third phenomenon can also be observed. The increased generation due to CHP units within the system in the cold season results in price and, thus, demand effects in the market in the winter and transition months. As a result, the graphs are flatter than in the solely PV scenario.

Figures 13 and 14 extend the findings from Figures 11 and 12, including the available sales volume for green regional electricity in the regional market. Figure 13 depicts the expansion scenarios (a) and (b), and Figure 14 shows scenarios (c) and (d). It is worth noting that, once again, this representation focuses on aggregated quantities rather than providing hourly analyses. What hits the eye first is that the sales volume is higher, and, as inferred from Figures 11 and 12, the demand is generally lower than in the solely PV scenario. This can be categorized as a positive effect on the overall system in scenario (a), even though this figure is a market analysis. Starting from scenario (b), it becomes apparent that the sales volume appears to be disproportionately large for the market's demand situation. In scenarios (c) and (d), the sales volume surpasses the quantity demanded, with (d) even experiencing this oversupply in the winter months.

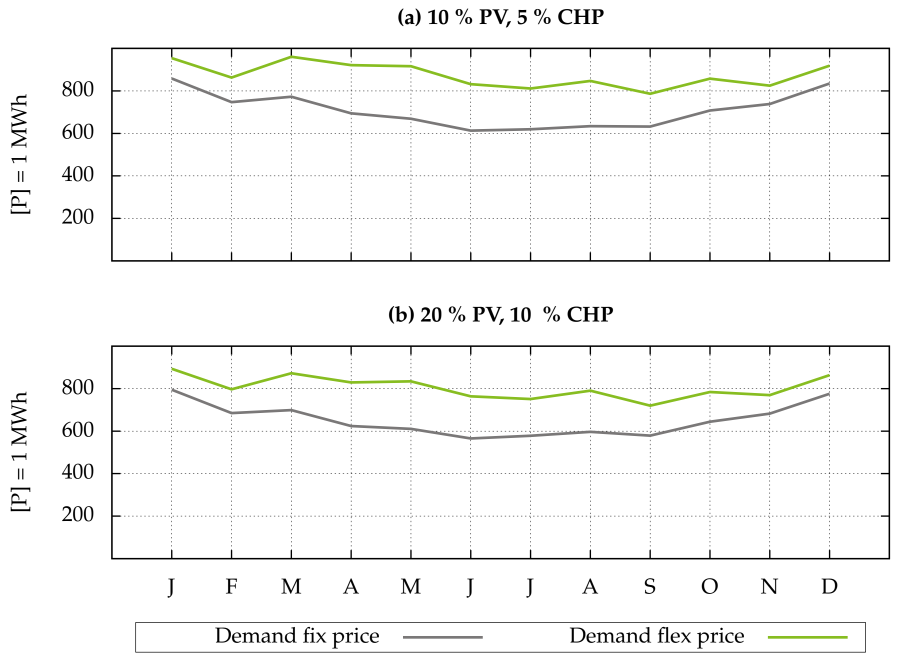

Figure 11. Total demand per month for regional green electricity in fixed and flex price systems over one year for PV and CHP expansion stages (a) 10% PV, 5% CHP and (b) 20% PV, 10% CHP.

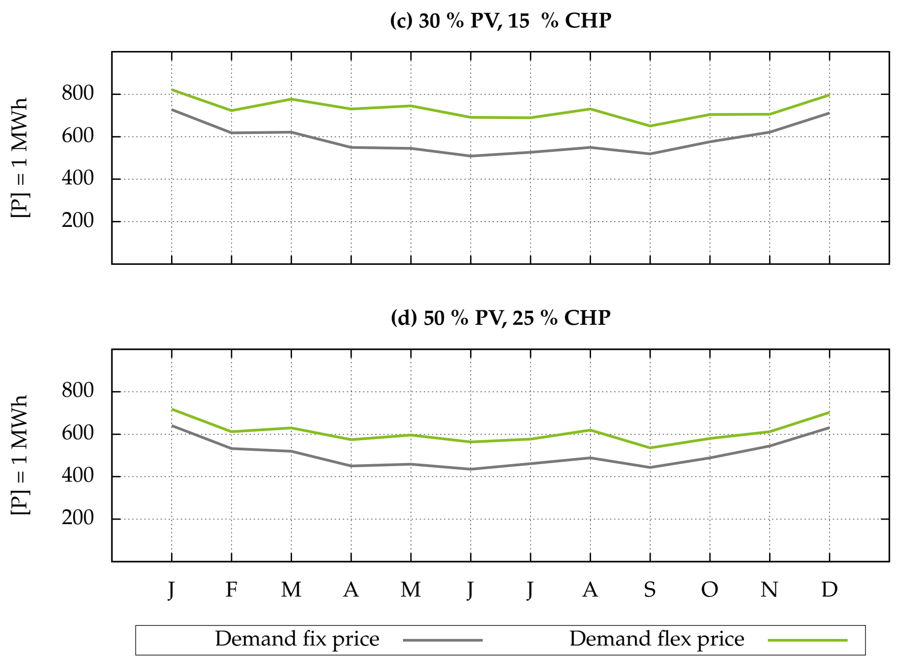

Figure 12. Total demand per month for regional green electricity in fixed and flex price systems over one year for PV and CHP expansion stages (c) 30% PV, 15% CHP and (d) 50% PV, 25% CHP.

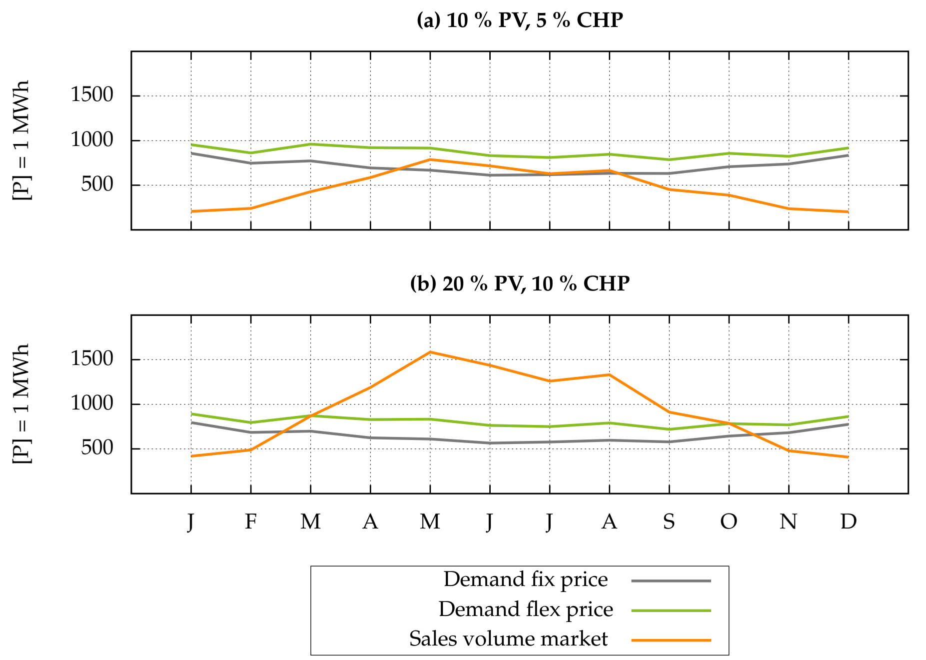

Figure 13. Relation between total demand in fixed and flex price scenarios and total sales volume per month for regional green electricity over one year for PV and CHP expansion stages (a) 10% PV, 5% CHP and (b) 20% PV, 10% CHP.

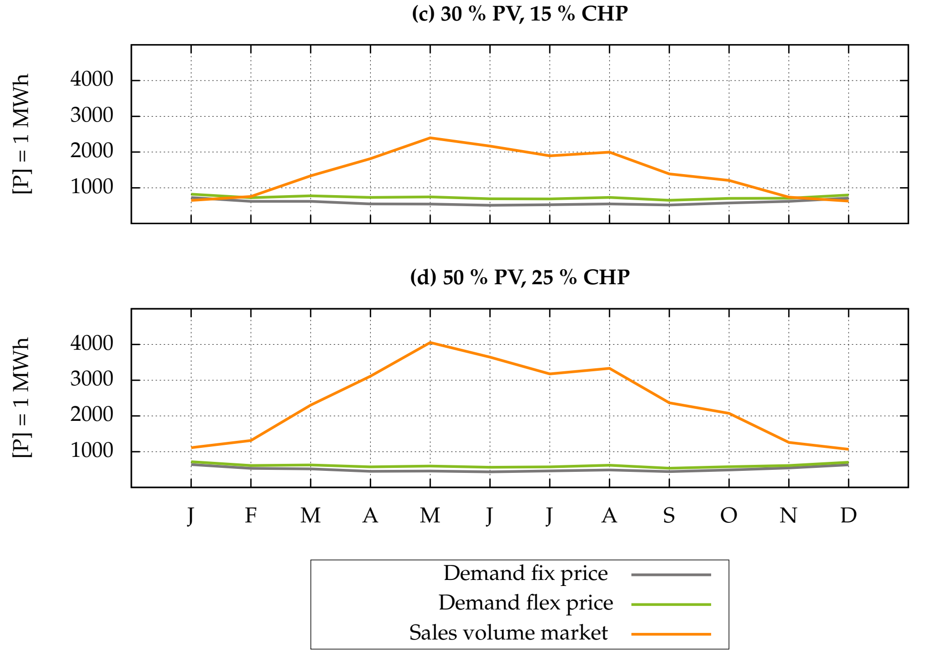

Figure 14. Relation between total demand in fixed and flex price scenarios and total sales volume per month for regional green electricity over one year for PV and CHP expansion stages (c) 30% PV, 15% CHP and (d) 50% PV, 25% CHP.

Figures 15 and 16 display the residual sales volumes for the regional market under both fixed and flex price systems. Figure 15 displays the expansion scenarios (a) and (b), and Figure 16 shows scenarios (c) and (d). Compared to the representation in the solely PV scenario (see Figures 8 and 9), it is noticeable that all graphs (a)–(d) later fall below 0, indicating a generally higher sales volume. However, in case (a), the graph remains at 0 for a while, suggesting a balanced level between demand and supply in the market. Scenarios (a) and (b) also show the positive effect of the flexibilization of the price component for green electricity. All scenarios (a)–(d) share the same maximum values as in the solely PV scenario, suggesting that these values are based on PV feed-in peaks. However, scenarios (c) and (d) show a significantly larger supply surplus than in the solely PV scenario.

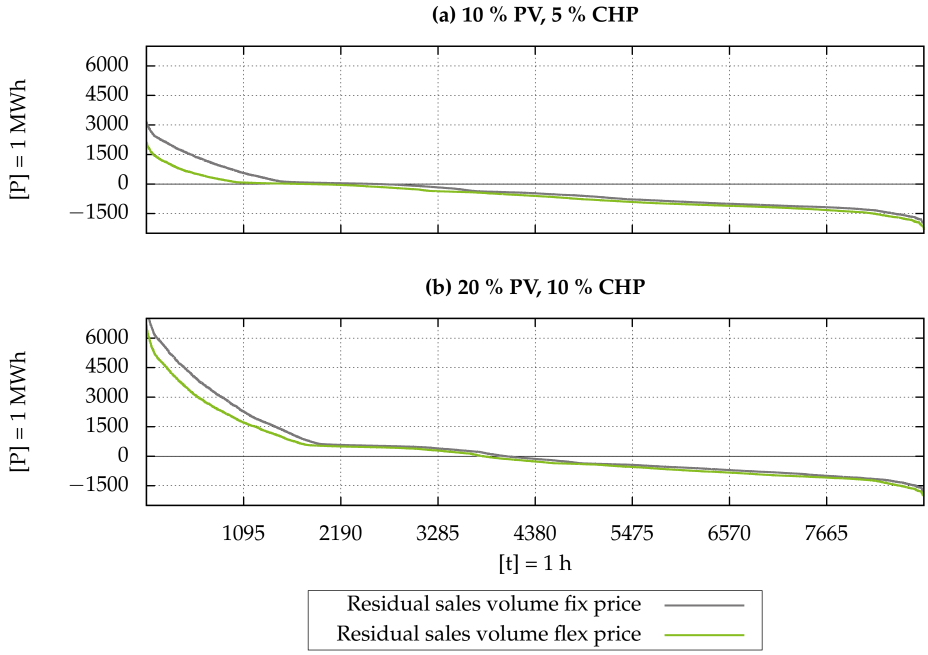

Figure 15. Ordered residual sales volume in fixed and flex price scenarios over one year for PV and CHP expansion stages (a) 10% PV, 5% CHP and (b) 20% PV, 10% CHP.

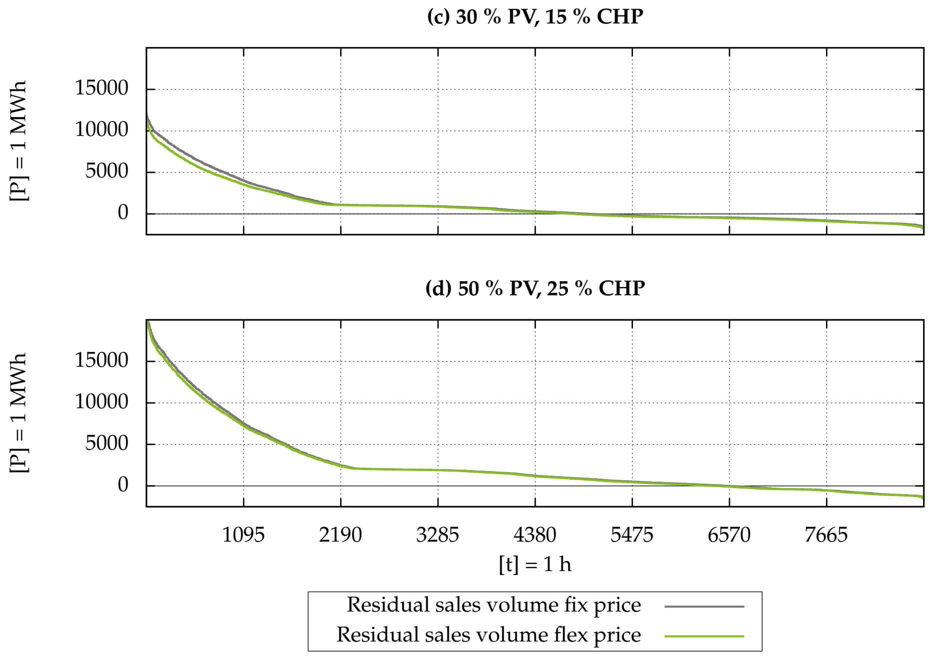

Figure 16. Ordered residual sales volume in fixed and flex price scenarios over one year for PV and CHP expansion stages (c) 30% PV, 15% CHP and (d) 50% PV, 25% CHP.

4.5. Scenario Results: Flex and Regio

Table 6 illustrates changes in demand for green regional electricity in scenarios PV (a)–(d). In these scenarios, the price component for the regional grid fee is discounted, in addition to the flexible price component for green electricity. It can be stated that there is a slight positive effect on the increase in demand resulting from the reduction in the regional grid fee. However, the increase in demand can be categorized as comparatively minor. It is particularly striking that there is no increase in scenario (b); instead, demand stagnates and even tends to decrease minimally.

Table 6. Difference in monthly demand [MWh] between flex and flex and regio price systems in PV scenario (a)–(d).

Month	(a) 10% PV	(b) 20% PV	(c) 30% PV	(d) 50% PV
Jan	3.88	−1.39	1.97	−0.57
Feb	2.43	−0.68	2.72	1.52
Mar	2.17	−0.41	4.43	3.04
Apr	2.26	−0.11	5.46	3.78
May	2.49	−0.10	6.02	4.44
Jun	2.10	−0.15	5.60	4.74
Jul	1.86	−0.33	5.61	4.03
Aug	2.70	−0.39	5.71	3.35
Sep	1.08	−0.45	4.47	3.96
Oct	1.85	−0.83	4.09	2.21
Nov	2.66	−1.22	2.22	0.29
Dec	4.00	−1.78	1.73	−1.27

Table 7 presents the results for the PV and CHP (a)–(d) scenarios, taking into account the discount on the regional grid fee. A positive effect on the increase in demand resulting from the reduction in the grid fee is observed in scenarios (a) and (c), particularly noticeable in winter months when compared to the results in Table 6. However, it is essential to note that the increase in demand can still be categorized as comparatively minor when considering the overall demand. Notably, scenarios (b) and (d) exhibit hardly any or even slightly negative changes in demand.

Table 7. Difference in monthly demand [MWh] between flex and flex and regio price systems in PV & CHP scenario (a)–(d).

Month	(a) 10% PV, 5% CHP	(b) 20% PV, 10% CHP	(c) 30% PV, 15% CHP	(d) 50% PV, 25% CHP
Jan	21.86	2.60	18.30	−1.45
Feb	18.48	2.73	15.77	−1.08
Mar	19.11	3.32	16.10	−0.75
Apr	17.20	2.32	14.65	−0.58
May	15.04	1.59	13.52	−0.45
Jun	13.28	1.95	12.25	−1.31
Jul	13.09	3.05	12.74	−1.56
Aug	12.95	2.41	11.93	−1.40
Sep	15.54	3.03	13.40	−0.70
Oct	18.89	2.80	15.27	−0.80
Nov	20.48	2.16	16.29	−1.21
Dec	22.78	2.18	18.16	−1.77

5. Discussion

Figures 4, 5, 11, and 12, as well as Figures 8, 9, 15, and 16, paint a clear picture. Despite different supply structures, there is an increase and adjustment in demand, but the level of demand volumes remains roughly the same across scenarios (a) to (d) for the respective expansion scenarios and stages. Even with the adjustment of the regional grid fee as an additional discount to the overall electricity price, there was no significant increase in demand. A further discount in the price components, therefore, could potentially tap into more demand, but it is unlikely to surpass the demonstrated level. Thus, Hypothesis 1 can be stated as proven. Empirical evidence of this finding is shown in different econometric analyses about the distribution and preferences concerning the WTP for green electricity. For example, refer to [29,30].

Theorem 1. *The increase in demand for green electricity is constrained by finite capacities in both WTP and consumption. This limitation arises from the fact that these capacities cannot perpetually grow and are subject to inherent constraints.*

As demonstrated, consumer prices linked to the utilization of generation result in an adjustment of demand in a manner that benefits the grid. This phenomenon is particularly evident in Figures 8, 9, 15, and 16, specifically in the residual sales volume. However, in the modeling studies, this adjustment in demand was essentially a shift in available products rather than an actual modification in consumption. Achieving a genuine adjustment in consumption requires the use of technical aids such as storage technologies and controllable consumer appliances. The ongoing technical advances and increasing sales volumes of battery storage systems show the trend of balancing supply and demand already on the lowest possible level of cellular power systems. Additionally, market-available energy management software is widely used in order to mitigate the influence of fluctuating generation. For evidence of statistics, refer to [31,32] and similar.

Hypothesis 2 could therefore only partially be confirmed. The theorem is as follows:

Theorem 2. *With the necessary technical aids in place, an increase in the demand for green electricity is postulated to lead to a corresponding reduction in the effort required to establish an equilibrium between generation and consumption within the market area.*

Figures 3 and 10, as well as Figures 6, 7, 13, and 14, confirm Hypothesis 3 so far. In scenarios (a) and (b) of the respective expansion scenarios, positive effects are observed as a result of the increase in the number of prosumers, namely the total demand on the market decreases and the existing trading volume increases to a manageable level. Scenarios (c) and (d) show a partially exorbitant oversupply in all expansion stages. Figures 8, 9, 15, and 16 reinforce this picture. According to these figures, it must even be stated that the first negative effects can occur in the (b) scenarios without technical aids. The future development of the electricity market will show where this turning point may occur. There is no empirical evidence available up to now. Thus, according to Hypothesis 3, the theorem has to be formulated as follows:

Theorem 3. *In a supply system with a low number of prosumers initially, there is an initial positive impact on the supply of green electricity as the number of prosumers increases. However, this positive effect transitions into a negative impact at some point. Where this point lies cannot be stated generally. It varies case by case and is highly dependent on the specific situation of the supply system itself.*

The response to Hypothesis 4 highlights the pronounced seasonality of PV. Additionally, it has been illustrated that all feed-in peaks are attributed to PV. In Figures 6, 7, 13, and 14, positive effects quickly occur with PV, especially during months with likely high PV feed-in. However, to extend these effects to colder months, an excessively high number of PV installations (scenarios (c) and (d)) is required, resulting in the negative consequence of extreme oversupply in summer. The implementation of CHP mitigates the overall situation within the scenarios. All curves shown for scenarios with CHP are much flatter, indicating overall less volatile generation patterns. Scenario (a) in Figure 15 even exhibits hours with residual sales volume = 0, indicating an absolute system-supporting condition.

Of course, this development will probably be compensated to some extent by other technologies such as wind, water, and biomass power plants in a regional energy market. In order to illustrate these mutual influences, the current REMM needs to be extended.

Theorem 4. *A supply system exclusively dependent on solar PV prosumers is anticipated to witness heightened positive effects primarily during summer, reaching a peak up to a certain threshold. Beyond this point, the positive effects may diminish or even transition into negative consequences, necessitating further considerations for system resilience and adaptability.*

The analyses show which impact prosumers can have on a cellular system and which positive effect flexible market prices can have on the overall system. It provides a good insight into the opportunities and boundaries of regional energy markets based on cellular systems. Nevertheless, these analyses are not claimed to be exhaustive and can and will be further expanded upon.

The next starting point could be the adjustment of the flexible price mechanism, which is currently still based on the ratio of installed capacity to actual local generation and, therefore, only has a positive effect when generation is heading toward the maximum. PV-heavy systems only benefit in summer, and due to their inherent characteristics, there are no positive effects in winter.

Furthermore, no actual possibilities for increasing or shifting the load of consumers were taken into account. If not only demand but also consumption can be increased, this would possibly reinforce the effects. Additional permanent consumption technologies such as heat pumps could also have an equalizing effect.

Furthermore, no larger companies were considered that could be additional consumers of regional green electricity and thus have a smoothing effect on the residual load of the system.

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Abbreviations

The following abbreviations are used in this manuscript:

ABM	Agent-based modeling
BSL	Business with Standard Load Profile
CA	Cellular approach
CHP	Combined heat and power
LUC	Local utility company
PV	Solar photovoltaic
REMM	Regional energy market model
RES	Renewable energy source
RSL	Residential with Standard Load Profile
WTP	Willingness to pay

Appendix A. Data and Download

For additional information and to download the data, please consult the following:

NetLogo https://ccl.northwestern.edu/netlogo/ (last accessed on 26 January 2024)

Standard Load Profiles https://www.bdew.de/energie/standardlastprofile-strom/ (last accessed on 26 January 2024)

Weather Data https://www.dwd.de/DE/leistungen/testreferenzjahre (last accessed on 26 January 2024)

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