Shaping the energy transition in the residential sector: regulatory incentives for aligning household and system perspectives

Gianmarco Aniello[1,2] and Valentin Bertsch[2]

[1]Forschungszentrum Jülich, Institute of Energy and Climate Research – Systems Analysis and Technology Evaluation (IEK-STE), Jülich, Germany
[2]Chair of Energy Systems and Energy Economics, Ruhr-Universität Bochum, Bochum, Germany

https://doi.org/10.1016/j.apenergy.2022.120582

Abstract

The regulatory framework influences households' decisions in the context of the energy transition, affecting the potential for CO_2 emissions savings and the operation of the electrical network infrastructure. In this paper, the profitability and optimal operation of alternative home energy systems (HESs) consisting of photovoltaics (PV), battery energy storage (BES), and either a gas condensing boiler (GB) or an electrical air-to-water heat pump (HP) is investigated for the case of a German single-family house and across alternative regulatory scenarios. Two policy reforms are considered: (i) an alternative design of network tariffs, the objectives of which are the financial sustainability and the efficient operation of the power grid, as well as the cost reflectivity of such charges; and (ii) a CO_2-oriented reform of energy taxes and surcharges on retail energy prices. For the latter, the real-time carbon intensity of grid electricity is estimated and priced in dynamic retail electricity rates. After the optimization of the operation of each alternative HES under such alternative sets of price signals, a simulation over a 20-year planning horizon is carried out in order to evaluate each option in terms of profitability, impact on CO_2 emissions and grid integration. The findings show how a change of regulatory framework can foster a low-carbon-oriented and grid-friendly adoption and operation of energy technologies. In the case under analysis, a regulatory shift: (i) results in a decrease of up to 17% in the discounted lifetime costs of the HP heating, thereby steering the household's adoption decision toward a reduction of up to 63% in CO_2 emissions; (ii) induces a

grid-oriented operation of the HP and the BES, reducing coincident peak demand by up to 62%. The implications of such a regulatory shift are discussed in relation to the effectiveness, cost efficiency and distributional fairness of the energy transition in the residential sector.

1 Introduction and background

Over the last two decades, in order to tackle climate change, many countries have adopted policies fostering the deployment of renewable energy technologies (RETs). Such policies have aimed not only at promoting large-scale installations, but also small-scale installations for distributed electricity generation with a focus on self-consumption, such as rooftop PV systems for residential prosumers. One of the most prominent examples of support schemes to residential PV installations for homeowners is the German Renewable Energy Sources Act (EEG), which provides size- and technology-specific feed-in tariffs (FiTs). As a result, the installed capacity of PV has grown from less than 1 GW in the early 2000s to approx. 59 GW by the end of 2021, which consists of approx. 2.2 million installations [1]. While during a first phase, a swift uptake of residential PV was stimulated by very high FiTs (2009-2012), in a second phase, savings from self-consumption have been playing an increasingly important role in the economics of residential PV. As a result of a drop in the levelized cost of electricity (LCOE) and FiTs, as well as an increase in electricity retail prices, German prosumers have become "residual producers", meaning that they aim primarily to maximize self-consumption and secondly inject the remaining PV power into the grid [2]. Consequently, around the mid 2010s, a new trend emerged among homeowners, in that they started adopting residential PV systems in combination with battery energy storage (BES) in order to increase their degree of self-sufficiency and independence from increasingly expensive power suppliers [3]. Around 60% of newly installed PV are nowadays coupled with a BES and such a trend seems to be gaining momentum,[1] while retrofits of existing PV installations are expected to grow in the upcoming years [5]. However, PV promotion, as well as the indirect subsidization of residential PV self-consumption, have been strongly criticized since their early phases due to their economic inefficiency and unfair distributional effects (see [6, 7, 8, 9, 10]). In this respect, the growth in retail rates is linked to the same surge in prosumers and, more generally, RETs' deployment.

Firstly, the diffusion of prosumers might have already contributed,[2] and might increasingly contribute in the future, to an increase in network charges. This effect occurs through several impact channels:

[1] According to recent estimations,in 2021 residential BES systems increased by 45% with respect to the previous year [4].

[2] Average network charges for household customers increased from 5.70 ct/kWh to 7.5ct/kWh between 2011 and 2020, even though the reform of avoided network charges (NEMoG) and the exclusion of off-shore network charges have in part counteracted this upward trend. The main drivers for increasing costs were grid expansion and system security measures [11].

- Self-consumption of PV electricity results in substantial bill savings because prosumers avoid paying regulated volumetric components including network charges. Grid costs, however, are mainly fixed and depend on capacity rather than volumes, which is why missing revenue from prosumers needs to be recovered through higher charges from the remaining consumers.

- The integration into the grid of renewable power plants requires new investments in the expansion of the network. The coupling of PV with BES may mitigate the increase in network costs, but a system-friendly operation thereof is essential [12].

- The increment in volumetric network charges might incentivize more consumers to become prosumers, causing charges to increase further, resulting in a "utility death spiral".

Generally, prosumers may provide important beneficial contributions to the system (i.e., network losses reduction, improved demand response, bill savings and CO_2 emissions abatement). However, if their costs and benefits are not shared in a fair way because of non-cost-reflective network tariffs, they can pose challenges for network operation, for the long-term economic sustainability of the power system [13] and for those who cannot (afford to) invest in such self-consumption technologies.

Secondly, the EEG has contributed significantly to the growth in the remaining regulated components of retail rates: most notably through the EEG surcharge, a flat surcharge levied on electricity retail consumers,[3] which finances FiTs and in 2021[4] accounted for approx. 20% of retail electricity prices [14]. While such a surcharge is levied on electrical consumption, including electric heating, electricity only accounts for approx. one fifth of energy consumption in German households [16]. As matter of fact, fossil fuel-based heating is responsible for most residential emissions.[5] The focus of the EEG and of its financing mechanism on the electricity sector may disincentivize sector coupling and the adoption of low-carbon technologies such as electrical heat pumps.[6] In contrast to retail rates, wholesale electricity prices have remained stable or even declined

[3]This surcharge rapidly soared from values around 1 ct/kWh in the late 2000s up to values between 6 and 7 ct/kWh since the mid 2010s [11].

[4]In 2022, for the first time, the EEG surcharge fell significantly, namely by approx. 43% [14]. The causes of such a drop were the exceptionally high wholesale electricity prices, meaning higher revenues for RETs' generation, and the contribution from the federal budget, which was financed with the revenue from the recently introduced national CO_2 pricing scheme [15]. At the time of writing, Germany's new coalition government decided to fully abolish this surcharge, meaning that the RETs promotion schemes will be financed through the federal budget.

[5]In 2019, combustion in residential buildings resulted in approx. 90 million t CO_2 equivalent[17], while electrical consumption from households was responsible for approx. 54 million t CO_2 equivalent (own estimation, based on [18] and [11]).

[6]In the heating sector, the reduction in greenhouse gas emissions has been promoted through mandates on heating technologies and efficiency standards for new and refurbished buildings, as well as grants for replacing old heating systems.

over the last decade, with average annual values of around € 30-40/MWh until very recently [19],[7] meaning that the wholesale electricity market has played an increasingly minor role in shaping retail tariffs. Last but not least, the sharp variation in carbon intensity of the electricity generation mix is not reflected in end-consumer prices. Beyond the German context, in several other countries (see for instance [20]), the current design of retail energy tariffs does not appear to facilitate the energy transition. In this paper, the impact of the tariff design is explored by introducing two regulatory reforms, which aim to align retail-level price signals with incentives for a grid-friendly and low-carbon-oriented adoption and operation of energy technologies in the residential sector, as well as to improve the reflectivity of the allocation of energy system costs among grid users and energy consumers. The first reform consists of a new design of electricity network charges, namely a shift from volumetric to capacity-based charges, which also consider the real-time conditions of the electrical grid. With respect to the second regulatory shift, firstly dynamic retail electricity pricing is implemented, followed by the application of a revenue-neutral energy reform. Such a reform abolishes all taxes and surcharges on retail energy rates and replaces them with a uniform CO_2 pricing mechanism across all energy sectors, whereby hourly electricity prices strongly reflect the carbon intensity of the electricity generation mix. The scope of this study is limited to the assessment of home energy systems (HESs) consisting of photovoltaic (PV) and battery energy storage (BES) systems, and either a gas condensing boiler (GB) or an electrical air-to-water heat pump (HP). The analysis is carried out by means of a two-stage techno-economic model: firstly the first year of operation of 50 possible HESs (i.e., combinations of PV, BES and GB/HP) is optimized for the case of one typical household across five alternative regulatory scenarios; secondly the optimized operation results are extended over a 20-year investment planning horizon (IPH), assessing the financial performance, impact on carbon emissions, and impact on grid-friendly behavior in terms of coincident demand and injection peaks, under each regulatory scenario. While there is a large body of literature dealing with the alignment of retail energy tariffs with a system perspective across many country-specific cases (cf. Section 2), this is, to the best of the authors' knowledge, the first study to investigate (i) such a novel set of grid-oriented and carbon-oriented dynamic price signals; (ii) the impact thereof on the profitability and operation of both prosumage and heating technologies; and (iii) the system-level implications in terms of grid integration and carbon emissions.

The remainder of this paper proceeds as follows. Section 2 provides an overview of the related literature. In Section 3, the current regulatory framework and the alternative regulatory scenarios are presented; the data and assumed system parameters are described. Section 4 provides a description the techno-economic model. In Section 5, the results are presented. Section 6 discusses the findings and provides an outlook for further research. Section 7 concludes.

[7]Since the second half of 2021, wholesale electricity prices have soared to unprecedented levels [19], following a sharp increase in the price of natural gas and EU ETS allowances. The Ukraine crisis of 2022 has further aggravated the surge in energy prices.

2 Literature review

Many studies have analyzed the end-consumer economics and the optimal sizing of PV and BES systems for residential prosumers, focusing on several aspects such as optimal technical configuration (e.g., [21, 22]), load and/or geographical heterogeneity (e.g., [23, 24, 25, 26]), alternative support and regulation schemes (e.g.,[27, 28]), fiscal, financial aspects and economies of scale (e.g., [29, 30]), optimal operation strategies (e.g., [31, 32, 33]), the coupling with other technologies such as HPs and electrical vehicles (EVs) (e.g., [34, 35]). In this strand of literature, battery coupling has been generally found to be financially sub-optimal and less cost-efficient than other load control devices (such as HPs with heat storage). However, the interest in and adoption of BES is growing in several countries, meaning that co-benefits (e.g., back-up power) may play a decisive role [36]. In addition to assumed technology costs and load profiles, the differences in terms of tariff structure (e.g., volumetric vs capacity charges) is a main driver for diverging economic assessments [36]. A few studies [37, 38, 39] have investigated the impact of alternative rate structures on end-consumer economics, and have also considered the coupling with HPs [39] and EVs [38]. Similar to this paper, in this strand of literature, alternative tariff designs typically consist of a reform of network charges with a shift from volumetric to fixed or demand charges, a (partial) alignment of volumetric components (including feed-in rates) with real-time wholesale market prices through dynamic or time-of-use (TOU) rates, or limits and penalties for excess load and injection. While this set of studies has mostly focused on a techno-economic assessment from a prosumer perspective, they have also found that annual demand charges and excess load/feed-in penalties are effective in reducing household-level withdrawal (i.e., grid load) peaks, whereas TOU and dynamic pricing may even worsen this outcome [38, 39]. However, rather than household-level peaks, the demand that contributes to network-level peaks (i.e., coincident peak demand) is relevant to assess system-level impacts.

Several studies have aggregated household-level decisions in order to gauge the impact of the optimal investment and dispatch of PV-BES from a prosumer perspective on the power system cost-minimal investment and/or dispatch. They have found that exclusively focusing on the maximization of self-consumption results in a sub-optimal system, i.e., higher system costs and possibly GHG emissions, (e.g, [7, 12] in the case of Germany, [40] in the case of Sweden, [41] in the case of Switzerland, [42] in the case of the UK, [43] in the case of Australia). A further subset of this literature has focused on the assessment of different kinds of welfare and system-level impacts across alternative regulatory scenarios, both in the German case and elsewhere. Klein et al. [44] proposed a market alignment indicator, which evaluates the system-friendliness of the operation of PV-BES systems across regulatory scenarios by comparing it to a benchmark operation, in which such systems are fully integrated in the electricity wholesale market. They considered several regulatory shifts (dynamic retail prices, dynamic feed-in rates, fixed network charges) and found that the simultaneous implementation of all of these results in the highest level of market alignment, yet they did not consider grid constraints. Fett et al. [45] devised several regulatory scenarios, across which they estimated the level of PV-BES diffusion and its impact on retail electricity prices. In addition to the current regulatory scenario, they considered a fully fixed network charge, an annual demand charge, as well as dynamic export rates and a partial EEG surcharge on self-consumption, and calculated a price increase of 16.5% in the case of the reference scenario and significant increases even in the case of demand charges. For the case of California, Schwarz et al. [46] considered alternative feed-in remuneration schemes and volumetric charges, and even proposed a fixed monthly charge for PV owners, which they considered to be crucial for mitigating future increases in retail prices. For the case of the UK, Pimm et al. [47] studied the impact of introducing TOU rates on load and feed-in peaks in the distribution grid. They found that, even in areas with high-penetration of PV and HP, batteries did not help to reduce such peaks, and in fact sometimes even increased peak demand at low-voltage substations. They proposed several approaches to avoid such so-called rebound peaks, including capacity charges both for demand and feed-in. In contrast to most of the related literature, Young et al. [48] obtained more optimistic results. They considered PV-BES operation under flat volumetric charges, TOU volumetric charges, as well as time-varying monthly demand charges, which are based on typical load peak times of the analyzed Australian region. They scaled up their household-level results to estimate network-level peaks, the reduction in revenue for DSOs (distribution system operators) and the potential mitigation of long-run marginal network costs. They found that prosumers with PV-BES systems reduced network-level demand peaks across all regulatory scenarios, and that cost mitigation exceeded the drop in revenue, especially in the case of demand charges. Günther et al. [49] analyzed many regulatory frameworks with respect to both withdrawal and feed-in rates, which differ in terms of flat volumetric rates, fixed charges, real-time volumetric rates and feed-in limits. They found that none of the scenarios reduced system-level demand peaks and feed-in peaks were reduced only through fixed limits. Furthermore, they assessed the reduction of the contribution to non-energy power system costs, which was only mitigated in the scenarios with high fixed charges. Fett et al. [50] considered four scenarios,[8] for which they estimated residential PV and BES uptake using a dynamic diffusion model, also taking into account non-financial factors and the iterative interactions between prosumer- and system-level decisions. They concluded that policy makers should focus on the system-friendly operation of BES. In particular, they found that a dynamic battery operation, which aims to lower feed-in peaks, may reduce by more than 10% the curtailment of renewable electricity generation. Thomsen et al. [51] devised scenarios with respect to real-time electricity withdrawal and feed-in rates, as well as with respect to policy reforms by considering higher fixed grid charges (more precisely, a contracted capacity charge) and a time-varying EEG surcharge. They investigated

[8] One scenario involved a regulatory reform consisting of a fixed network charge, a feed-in limit, dynamic feed-in rates and a reduced EEG surcharge on self-consumption.

the impact of a number of (prosumer) households on a local power system and found that scenarios with time-varying rates showed a higher system peak load and coincidence factor, which resulted in higher stress on the local grid. The authors underscored how "system-friendly operation" must be defined carefully, since the market and the grid perspective do not coincide.

However, such a mismatch (also found by [47, 49]) between market and grid integration, might be due to the fact that the wholesale electricity market fails to convey a high degree of spatially-granular price signals, and that the corresponding real-time prices do not reflect potentially critical periods in the local distribution grid. As a matter of fact, in the case of Germany, the wholesale electricity market consists of only one bidding zone, meaning that network constraints are entirely overlooked in the wholesale pricing mechanism. In an "ideal world", time-varying locational marginal prices (LMPs) would be expected at each connection point of the electrical grid, and such LMPs would reflect both short-run (e.g., generation) and long-run (e.g., network expansion) marginal costs [52]. However, LMPs at the level of the distribution grid would involve a degree of complexity that would make them infeasible for real-world applications [52]. On the other hand, forward-looking price signals are needed to reflect the marginal future costs of the grid and improve the long-run system efficiency [52, 53]. Peak-coincident network capacity charges (or dynamic network tariffs), levied on both withdrawal and injection and featuring a sufficient level of locational granularity, can provide such price signals [52, 54, 53].

This paper considers the different objectives of network charges (i.e., recovery of sunk costs, cost reflectivity, cost efficiency) and respective measures to achieve them (i.e., coincident and non-coincident capacity charges). Accordingly, a consistent structure for such time-varying, capacity-based network charges is proposed. Subsequently, the impact of such a regulatory shift on households' coincident peak demand and feed-in is examined. Such an assessment of this regulatory reform represents the first contribution to the literature on the techno-economic evaluation of prosumage across alternative regulatory scenarios, from both an end-consumer and a system perspective.

The aforementioned new design of network charges aims to improve the cost reflectivity of grid charges, as well as the efficiency of grid operation. In other words, it aims towards the grid integration of distribution grid users, especially when they are prosumers or operate load control devices (e.g., heat pumps). Market integration requires a different set of price signals. For this reason, the paper's second contribution to the literature involves considering a second regulatory reform, which aims to improve the cost reflectivity of retail energy prices, thereby steering households towards low-carbon-oriented investment and operation decisions, both as energy consumers and as prosumers. Therefore, not only are real-time power rates applied to residential consumers (similar to many studies cited above), but a CO_2-oriented reform of energy surcharges and taxes is also implemented, according to which end-consumer dynamic energy prices internalize the cost of the embedded real-time CO_2 emissions. To the best of the authors' knowledge, this is the first study on prosumage to implement this type of reform,[9] while estimating the real-time CO_2 intensity of grid electricity, thereby assessing the impact of households' energy consumption on CO_2 emissions.

Finally, the evaluation of a power-to-heat technology is a further contribution to the literature. The paper examines the decision to adopt either a modern gas condensing boiler (GB) or an electrical air-to-water heat pump (HP), focusing on how alternative regulatory frameworks affect the relative profitability and operation of the latter. Although an advanced technical modeling of building heating demand is beyond the scope of this study, the authors believe that the heating sector is essential for the analysis, since power-to-heat technologies (especially HPs) are expected to play an increasingly central role in reducing CO_2 emissions and in integrating RETs into the power system [55, 56].

3 Data and assumptions

3.1 Weather, PV generation and load profiles

Temperature and PV generation[10] profiles for the location of the city of Essen were obtained from the online tool Renewables.ninja [57, 58, 59]. These data consist of hourly time series for the year 2019, which were converted to a 15 min resolution through linear interpolation. The average annual temperature of the selected location was 10.2°C, whereas the PV generation was 1088 kWh/KW_p. For demand-side data, synthetic load profiles generated by the *LoadProfileGenerator* (LPG) [60] were used. This tool simulates the consumption of electricity and domestic hot water (DHW) in a 1 min resolution, while it allocates the annual space heating demand in a 24 h resolution based on the external temperature. The three types of load profiles were converted to a 15 min resolution. For the space heating (SpH) load profile, within the LPG a 150 m^2 house with an annual space heating demand of 15,000 kWh was selected, which is based on an annual sum of 4,000 heating degree days. After inputting the temperature profile of the selected location (Essen), the LPG generated a space heating load profile with a total annual demand of 12,895 kWh. The electrical load and the DHW load depend on the behavior of household members, which is why a predefined[11] household type within the LPG was selected (i.e., *CHR27 Family both at work, 2 children*). With regard to domestic hot water, the LPG produced a DHW profile in liters that was then converted to kWh by multiplying it by 0.0525, which corresponds to the energy needed (in kWh) to heat 1 l of water at 10 °C to a temperature of 55 °C. Table 1 shows the annual level of energy demand for the households.

[9] In a similar fashion, Thomsen et al. [51] implemented a revenue-neutral dynamic EEG surcharge that also amplified the time-varying component of power rates, but failed to fully capture the real-time CO_2 intensity of the electricity mix.

[10] For the production of PV generation data, system losses were set at 15%, panels' inclination and azimuth were set at 30° and at 180° (i.e., southward facing), respectively.

[11] Only one modification was made: the predefined vacation was replaced with a 20-day vacation period in July.

Table 1: Annual energy demand of the simulated household (kWh)

Household	Electrical devices	Electricity	DHW	Space heating
HH1	Random	4,903	2,659	12,895

3.2 Energy prices

3.2.1 Regulatory scenarios

In this study, five different regulatory scenarios were considered. Such scenarios shape the market signals, which, in turn, determine the financially optimal adoption and operation of HESs:

BAU This is the business-as-usual scenario which considers the retail energy rates available to household consumers in the first half of 2021, as it is assumed that the investment in the HES occurs at the beginning of such a year.[12] Electricity prices consist of two different tariffs: one for standard (std.) electricity and one for electricity used for heating. Both tariffs comprise a fixed charge (per connection) and a flat volumetric charge (per kWh). Regulated components constitute approx. three quarters of this retail tariff and are included in both fixed and volumetric charges: i.e.,fixed and volumetric network charges, fixed meter charges, concession fees, several energy surcharges (most notably the EEG surcharge, which is used to finance renewable energy), electricity tax and value-added tax (VAT) [14]. The tariff for retail gas prices also consists of a fixed and a volumetric charge. Finally, for electricity exported to the grid, the prosumer receives a flat feed-in tariff (FiT).

BAU_dyn This is also a business-as-usual scenario, meaning that no regulatory reform is implemented (except for the abolition of fixed FiTs). However, retail prices here include a minor dynamic component, which reflects the prices of the wholesale market and replaces the non-regulated part of the flat volumetric charge in the *BAU* scenario. Volumetric regulated price components, as well as fixed charges, are the same as in the *BAU* scenario. For electricity exported to the grid, the prosumer is paid a time-varying export rate that replaces the current flat FiT scheme.

CC_ref This scenario introduces capacity charges as a result of reformed electricity network charges. Both fixed and volumetric network charges are removed from the volumetric charges in the *BAU* scenario, while charges are levied on the maximum monthly demand, which is measured in kW withdrawn within 15 min periods. More specifically, two time-of-use demand charges are levied: one for user peaks coinciding with load peaks in the grid, and one for off-peak times. Similarly, an on-peak feed-in charge is levied on prosumers.

[12] Given that time series data used in the analysis are from 2019, the non-regulated components of BAU tariffs were adjusted to address such a discrepancy (cf. Appendix A.1).

Ene_ref This scenario implements a revenue-neutral energy reform encompassing all energy sectors. All energy taxes and surcharges are abolished and replaced by a uniform CO_2 pricing mechanism. In other words, electricity tax and all surcharges are removed from retail electricity rates, as is the energy tax on gas. In this scenario, gas retail prices and wholesale electricity prices increase. However, the large variation in emission intensity of the electricity generation mix sharpens the variance of wholesale electricity prices, providing a strong incentive for load shifting. Therefore, retail consumers are exposed to dynamic electricity prices. For electricity exported to the grid, the prosumer is paid a time-varying export rate that replaces the current flat FiT scheme.

CC&Ene_ref This scenario simultaneously implements the two reforms presented in the *CC_ref* and *Ene_ref* scenarios.

A detailed description of the tariff design in the two business-as-usual scenarios is provided in the Appendix A. The following subsections present the data and assumptions underlying the tariff design under the two proposed regulatory reforms.

3.2.2 *CC_ref* tariffs

In the case of standard electricity supply in the *BAU* scenario, the local DSO recovers a minor share of network costs through a fixed annual charge of € 78.18 (incl. VAT). The rest is allocated to household customers through a volumetric network charge of 6.88 ct/kWh for standard (std.) electricity and of 1.79 ct/kWh (incl. VAT) for heating electricity. In this scenario, both fixed and volumetric charges are abolished and replaced with capacity charges. The introduction of kW-based charges implies a fundamental restructuring of the way in which the infrastructure costs of the power grid are allocated. Infrastructure costs consist of past sunk costs and fixed operating costs, which are independent of power peaks, as well as current costs and future marginal costs, which depend on present and expected future power peaks. While the analysis and estimation of the past and future cost structure of local electrical networks is beyond the scope of this paper, considering the different nature of such costs is essential for designing cost-reflective network charges [54, 61]. With this in mind, the aim was to design a tariff pursuing the following objectives:

- **Cost recovery**, i.e., grid costs are recovered through network charges, meaning that grid users have to fully pay for this infrastructure.
- **Cost reflectivity**, i.e., the cost paid by each user reflects the degree to which each user is responsible for the capacity and cost of the network.
- **Cost efficiency**,i.e., the tariff favors a cost-efficient operation and expansion of the grid, by incentivizing a network-friendly use of the grid.

Based on this, a two-tier demand charge, levied on two different types of user's peaks, was designed.

The low-cost demand charge aims to recover sunk costs, and is levied on the maximum demand within a 15 min period on a monthly basis at times during which no demand peak occurs in the grid: this is known as an off-peak demand charge. This kW-based charge is considered superior to the current kWh-based charge, as network capacity and not energy quantity is a crucial driver of network costs and DSO should be financially independent of consumption volumes [54]. Alternatively, sunk costs could be recovered through a fixed charge, but this would counteract cost reflectivity (and distributional fairness), as low-consumption households would have to pay the same amount as high-consumption households. However, a minimum demand charge, which is equivalent to a fixed charge, is included here, as sunk costs include fixed costs, which are independent of network capacity (e.g., topology-driven costs).

The high-cost demand charge seeks to reflect the sunk costs of building a network with sufficient capacity for high-demand times; to reflect short-term (operating) and long-term (expansion) marginal costs; and to provide users with an incentive for reducing their demand during such peak demand times. It is levied on a monthly basis on the maximum demand, coinciding with such critical periods.[13] Such an on-peak demand charge is implemented through critical peak pricing, where users are notified in advance (typically one or two days) about critical periods [54, 53]. Following [52], an equal on-peak, feed-in charge was assumed, given that electricity injection during critical periods also contributes to driving up the marginal costs of the grid. Demand and injection coincident peaks tend to occur in different months (respectively winter versus summers months, cf. Table 2). Considering this and in order to avoid double billing prosumers, the coincident feed-in charge is levied only on the marginal maximum monthly feed-in that is above the maximum annual coincident demand.[14] In other words, it was assumed that prosumers already pay their fair share of network costs through demand charges only, as long as their monthly coincident feed-in, which occurs typically during summertime, is below their maximum annual coincident demand, which occurs typically during wintertime. In order to identify critical periods occurring in the grid, several network load times series were considered: the standard load profile (SLP) customers' load (i.e., *"Nicht leistungsgemessene Kunden"*), the total load and the total feed-in in the local distribution grid (published by the DSO *Westnetz*), as well the total load in the local transmission grid (published by the TSO *Amprion*). Moreover, DSO and TSO data were supplemented with the PV generation data for the selected location (cf. Section 3.1). PV generation time series could be more accurate in identifying potentially critical injection periods due to the high geographic concentration of PV prosumers. The aim of using multiple times series is to capture a broad spectrum of bottlenecks and congestion, which occur in different

[13] In line with [61, 52], not only the single highest annual network peak is considered a critical period, but so too are multiple high-load periods throughout the year. Moreover, such charges are levied multiple times (i.e., monthly).

[14] E.g., over the year, a prosumer reaches a maximum coincident demand of 6 kW, whereas in a given month, they have a maximum coincident feed-in of 8 kw. In such a given month, they will be levied the on-peak injection charge only on the additional 2 kW.

parts and levels of the grid. All data cover the year 2019 and have a 15 min resolution. In this analysis, a critical load period was defined as a 15 min period in which the value of at least one of the three network load categories is above the 95th percentile, whereas a critical injection period is a 15 min period in which the feed-in in the distribution grid exceeds the load, or in which PV generation is above the 95th percentile.

The rates of the capacity charges were calibrated on the basis of two household load profiles[15] and according to the two following principles: if both households have a GB, no PV and no BES, they will be paying approx. the same level of network charges in either regulatory scenario; the values for on-peak and off-peak charges should differ significantly. Consequently, the monthly coincident capacity charge was set to € 5/kW, and the monthly non-coincident demand charge was set to € 2.5/kW. For the latter charge, the monthly minimum kW value was set to 2.6 kW, which is equivalent to the fixed charge of the *BAU* scenario. Such capacity charges were cross-validated by estimating the current total revenue of the local DSO and the potential revenue under this alternative regulatory design. It was found that the assumed rates are rather conservative, as only the revenue from demand charges (i.e., not from injection charges) would suffice to recover the DSO's revenue, which is currently obtained through volumetric and fixed charges (cf. Appendix B for more details).

Table 2: Occurrences of peaks in the grid (No. of 15-minute periods)

	Load												**Injection**											
	Month																							
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0	0	0	4	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0	0	0	4	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0	0	0	1	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	4	0	0	0	0	0	3
6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	5	0	0	4	0	0	0	0	0	8
7	46	27	0	2	0	0	0	0	0	0	5	13	0	0	4	0	0	1	0	0	0	0	0	5
8	75	55	12	0	0	0	0	0	0	0	19	37	0	0	0	0	0	0	0	0	0	0	0	0
9	73	49	27	7	2	2	0	0	0	0	23	29	0	0	0	15	22	13	7	1	0	0	0	0
10	79	54	35	10	4	14	0	0	0	5	34	29	0	4	24	57	50	83	64	53	28	0	0	0
11	92	67	60	12	4	11	0	0	0	10	48	41	0	27	28	63	60	89	73	73	47	3	0	0
12	99	61	50	5	4	6	0	0	0	7	50	38	0	28	28	68	54	78	66	71	51	7	0	0
13	94	48	38	1	4	0	0	0	0	0	41	33	0	4	25	57	43	58	56	51	32	2	0	0
14	93	35	20	0	0	0	0	0	0	0	23	35	0	0	3	24	23	16	19	6	1	0	0	0
15	101	27	21	0	0	0	0	0	0	0	24	47	0	0	0	0	0	0	0	1	0	0	0	0
16	96	17	7	0	0	0	0	0	0	0	28	60	0	0	0	0	0	0	0	0	0	0	0	0
17	124	38	10	0	0	0	0	0	0	3	86	108	0	0	0	0	0	0	0	0	0	0	0	0
18	124	83	33	0	0	0	0	0	0	3	95	115	0	0	0	0	0	0	0	0	0	0	0	0
19	124	75	56	0	0	0	0	0	0	0	30	85	0	0	0	0	0	0	0	0	0	0	0	0
20	86	29	8	0	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	0	0	0	0
21	75	20	0	0	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	0	0	0
22	28	3	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0

[15] Namely, the synthetic load profile used in this analysis (cf. Table 1), and a similar one for a household with only energy saving devices, thus characterized by a significantly lower annual electrical demand (i.e., 3,284 kWh as opposed to 4,903 kWh).

3.2.3 *Ene_ref* tariffs

This second reform seeks to improve the cost reflectivity of retail tariffs with respect to real-time generation costs, and, most importantly, the carbon intensity of the real-time generation mix. In order to design the electricity rates of the *Ene_ref* scenario, several data sources were used: wholesale electricity prices, CO_2 prices of the EU Emissions Trading System (ETS), electricity generation by production type and emission factors thereof (cf. Appendix C for details). All data cover the entire year in 2019, and are therefore consistent with all data used in this paper.

Energy rates in this scenario were determined as follows: Firstly, a time series of the hourly CO_2 intensity of the German electricity mix was estimated using multiple data sources (cf. Appendix C for a detailed description). Secondly, the data on carbon intensity were merged with wholesale electricity market and ETS allowances data in order to derive the cost component of CO_2 prices within hourly MWh prices. Finally, the alternative wholesale electricity prices were calculated, which include a CO_2 price set at € 125/tCO_2, as opposed to an average ETS allowance price in 2019 of approx. € 25/tCO_2. According to a study by Agora [62], such uniform CO_2 pricing across all energy sectors at this value could replace all non-carbon-oriented taxes and surcharges, which are currently levied on electricity and fossil energy carriers, without affecting government revenues. It was assumed that a CO_2 price surcharge, which makes up the difference between the national CO_2 price and the EU ETS price, is levied on the consumption side, whereas conventional electricity producers would be still subjected to EU ETS prices. In this estimate with data from 2019, such a reform would push up the (non-volume-weighted) average day-ahead demand-side price of wholesale electricity from € 37.6/MWh to € 77/MWh (excl. VAT), meaning that an average net increase of 3.94 ct/kWh would be passed on to retail consumers. However, retail energy charges would fall, as the increase in average wholesale prices would not even compensate for half of the abolished surcharges plus the electricity tax, amounting to 9.65 ct/kWh in total (in 2021, excl. VAT).[16] Figure 1 shows the distribution of the dynamic volumetric component of retail prices (incl. VAT on positive values) in relation to the carbon intensity of power generation: prices range from -7.62 ct/kWh to 21.53 ct/kWh; carbon intensity ranges from 131 g CO_2/kWh to 611 g CO_2/kWh. In this scenario, the injection of electricity into the grid is remunerated with the same dynamic prices (excl. VAT). In order to derive final dynamic retail electricity kWh charges, the remaining regulated components, which are part of the retail tariffs, were added. These are the location-specific concession fee of 2.84 ct/kWh (incl. VAT), and, if no network charges reform is simultaneously implemented, location-specific volumetric network charges of 6.88 ct/kWh (incl. VAT) for standard (std.) electricity and 1.79 ct/kWh (incl. VAT) for heating (or HP) electricity. Moreover, it was assumed that utilities do not charge a volumet-

[16] Namely, electricity tax (2.05 ct/kWh), EEG surcharge (6.5 ct/kWh), surcharge under KWKG (0.254 ct/kWh), surcharge under Sect. 19 StromNEV (0.439 ct/kWh), surcharge under Sect. 18 AbLaV (0.009 ct/kWh), offshore network surcharge (0.0395 ct/kWh) [63].

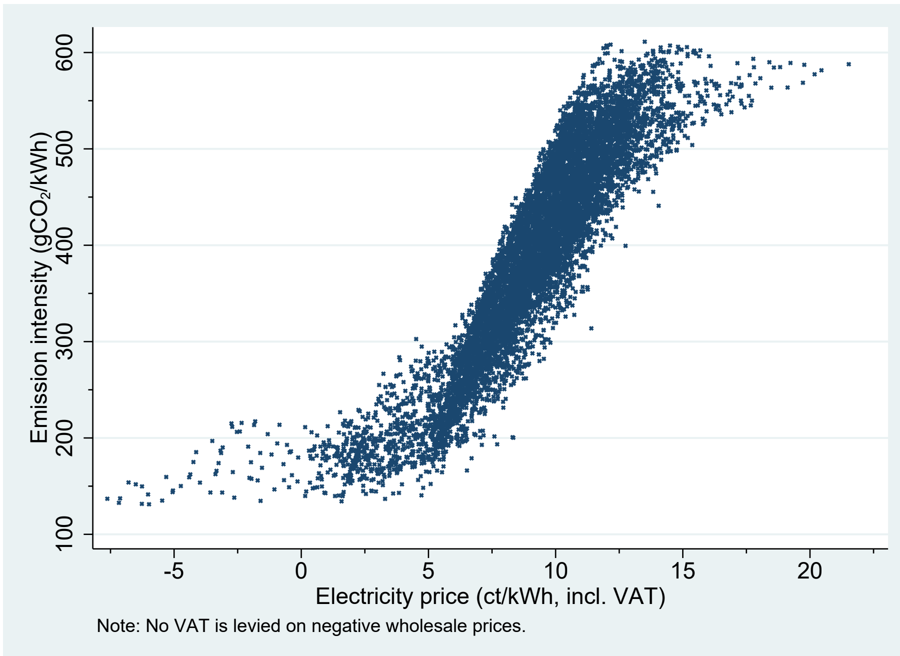

Figure 1: Dynamic volumetric component of retail electricity rates under the *Ene_ref* scenario (incl. VAT) and carbon emission intensity of grid electricity (own analysis)

ric markup on electricity rates, i.e., electricity suppliers charge their markup and recover their non-energy related costs only through the fixed component of electricity tariffs.

As a result of the same reform, the gas retail tariff increases to 6.17 ct/kWh. The abolition of the energy tax (0.55 ct/kWh) is more than offset by a 5-fold increase in CO_2 pricing[17] (from 0.46 ct/kWh to 2.3 ct/kWh).

3.2.4 Summary of energy tariffs

Table 3 summarizes the structure of the energy tariffs in each regulatory scenario. The values and ranges of values refer to the first year of analysis. For the sake of clarity, the flat volumetric charges and dynamic volumetric charges, which together compose the volumetric electricity rates, are reported separately.

Table 3: Structure of electricity and gas tariffs (dynamic rates are reported as value ranges; negative values indicate revenue; incl. VAT)

Scenario	Charge type	Std. withdrawal	HP withdrawal	Feed-in (<10 kW)	Feed-in (>10 kW)	Gas
BAU	Flat volum. (ct/kWh)	26.07	19.41	-8.16	-7.93	4.63
	Fixed (€/year)	118.52	66.46	-	-	136.69
BAU_dyn	Flat volum. (ct/kWh)	21.2	16.11	-	-	4.63
	Dyn. volum. (ct/kWh)	[-9.00,14.45]		-[-9.00,12.15]		
	Fixed (€/year)	118.52	66.46	-	-	136.69
CC_ref	Flat volum. (kWh)	19.19	17.63	-8.16	-7.93	4.63
	Fixed (€/year)	40.34	66.46	-	-	136.69
	On-peak capacity (€/KW/month)	5		5		-
	Off-peak demand (€/KW/month)	2.5 (min 2.6 kW)		-	-	-
Ene_ref	Flat volum. (ct/kWh)	9.72	4.63	-	-	6.16
	Dyn. volum. (ct/kWh)	[-7.62,21.53]		-[-7.62,18.08]		
	Fixed (€/year)	118.52	66.46	-	-	136.69
CC&Ene_ref	Flat volum. (ct/kWh)	2.84		-	-	6.16
	Dyn. volum. (ct/kWh)	[-7.62,21.53]		-[-7.62,18.08]		-
	Fixed (€/year)	40.34	66.46	-	-	136.69
	On-peak capacity (€/KW/month)	5		5		-
	Off-peak demand (€/KW/month)	2.5 (min 2.6 kW)		-	-	-

3.3 Home energy system components

All HES components were assumed to have a lifetime that matches an investment planning horizon (IPH) of 20 years. In the case of a HES with a HP, all HES components are connected and operated interdependently by means of an energy management system (EMS). Figure 2 shows a schematic representation of such a HES, as well as the electricity and heat flows between the different system components,[18] the energy loads and the grid. When the HES comprises a GB instead of a HP, the heating system operates independently of the other HES components and is only coupled with a DHW storage tank. A total of 50 different HESs were considered. These were combinations of 5 alternative options for PV systems, 5 alternative options for BES and 2 alternative heating systems.

Table 4 shows the input parameters[19] of the PV systems. A reference value of € 1050/kW$_p$ (excl. VAT) for a PV system with a power rating slightly below 10 kW$_p$[20] was assumed. The economies of scales affecting the cost of other system sizes were derived from the literature[21]. The operating costs were set at

[17] A novel CO_2 pricing scheme for energy carriers in the heating and transportation sector has been in force since 2021. The price for 2021 was set to € 25/tCO_2.

[18] Namely, a PV array and its respective inverter, an AC-coupled BES with its inverter and converter, an EMS that optimizes the electricity dispatch, an electrical air-to-water heat pump and two heat storage tanks at 35 °C (HS35) and at 55 °C (HS55) for space heating and DHW, respectively.

[19] PV generation was not simulated, as PV generation profiles were obtained from *Renewable.Ninjas* (cf. Section 3.1). Therefore, aside from sizes, the only technical parameter was the PV output degradation, which was inputted into the investment module of the techno-economic model (cf. Section 4).

[20] Such a price level represents a moderately optimistic assumption, reflecting a PV installation under ideal conditions.

[21] In accordance with [29], an increase in cost per kW$_p$ of 21% was assumed for the 5 kW$_p$

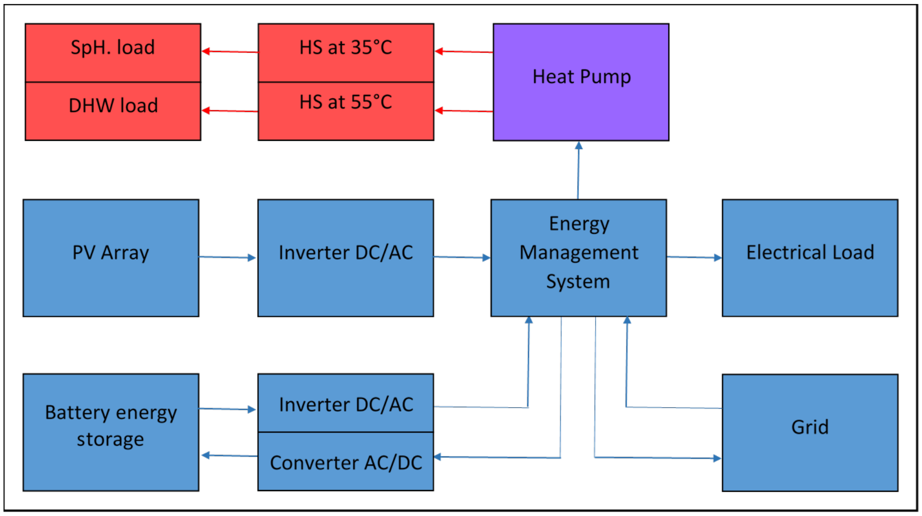

Figure 2: Schematic diagram of the HES

a fixed annual value of € 100 combined with additional costs of € 10 per $\mathrm{kW_p}$ (see [30]).

Table 4: Parameters of alternative PV systems

Description	Symbol	Values				
Nominal power (kW)	PV_pow	0	5	7.5	9.9	15
Annual degradation (%)	PV_deg	0.5				
Investment costs (€)	$capex^{PV}$	0	7559	10308	12495	17805
Operating costs (€/y)	$opex^{PV}$	0	150	175	200	250

Table 5 shows the input parameters of the alternative BES systems. The investment costs were based on an analysis of online prices of complete battery sets from two different producers,[22] which were characterized by significant economies of scale and to which a fixed installation cost of € 1000 € was added. It was assumed that the battery must be replaced once it reaches 80% of its initial capacity. BES replacement costs were set to a value of € 300/kWh (in

system and of 10% for the 7.5 $\mathrm{kW_p}$ system. For the 15 $\mathrm{kW_p}$ system, a decrease of 5% was assumed in the cost per $\mathrm{kW_p}$, in accordance with [64].

[22] All analyzed BES systems have the same kind of chemistry, namely Li-NMC (lithium nickel manganese cobalt oxide). Accordingly, the battery capacity fade was simulated by means of the System Advisory Model (SAM) [65], which includes a lifetime model for Li-NMC batteries (cf. Section 4).

accordance with [51]).

Table 5: Parameters of alternative BES systems

Description	Symbol	Values				
Nom. capacity (kWh)	BES_cap	0	3.3	6.7	10.0	13.3
Max. power (kW)	BES_pow	0	3.0	4.0	5.0	5.0
Charge efficiency	η^{cha}	0.96				
Discharge efficiency	η^{cha}	0.96				
Min SoC (kWh)	BES_soc^{min}	$0.15 \times BES\_cap$				
Max SoC (kWh)	BES_soc^{max}	$0.95 \times BES\_cap$				
Initial SoC (kWh)	BES_soc^{init}	$0.5 \times BES\_cap$				
Investment costs (€)	$capex^{BES}$	0	6614	7879	9299	9547
Operating costs (€/y)	$opex^{BES}$	0				
Replacement costs (€)	$repex$	0	990	2010	3000	3990

Table 6 shows the input parameters of the alternative heating systems, namely a gas condensing boiler (GB) and an electrical air-to-water heat pump (HP). For the GB, constant levels of efficiency and maximum output power were assumed. For the HP, a temperature-varying coefficient of performance (COP) and maximum output power (*opow*), as well as two operation modes with respect to output water temperature, were assumed. The variable technical parameters of the HP were derived from technical data sheets from a producer and are given in Table 12 in the Appendix D. Finally, investment and operating costs were based on a study by BDEW (German Association of Energy and Water Industries) [66]. Such investment costs aim to reflect the costs of totally refurbishing a single-family house and installing a new heating system (incl., radiators, pipes, etc.).

Table 6: Parameters of alternative heating systems

Description	Symbol(s)	Values and range		
Heating system	$HSYS$	GB	HP	
Operation mode	35\55	55 °C	35 °C	55 °C
Max power (kW)	$GB\_pow \backslash HP35\_opow_t \backslash HP55\_opow_t$	8	[5.77,12.01]	[5.19,10.68]
Efficiency\COP	$\eta^{gb} \backslash COP35_t \backslash COP55_t$	0.98	[2.47,9.27]	[1.66,5.46]
Storage (L\kWh)	$HS35\_cap \backslash HS55\_cap$	170\8.91	500\14.58	170\8.92
HS min SoC (kWh)	$HS35\_soc^{min} \backslash HS55\_soc^{min}$	1.78	0	1.78
HS initial SoC (kWh)	$HS35\_soc^{init} \backslash HS55\_soc^{init}$	2.23	0	2.23
HS self-discharge rate	σ	$0.85^{\frac{1}{96}}$		
Investment costs (€)	$capex^{HSYS}$	16400	26500	
Operating costs (€/y)	$opex^{HSYS}$	191	150	

3.4 Investment planning horizon

The analysis performed in this paper covers a 20-year investment planning horizon (IPH). A set of assumptions were made in this respect:

- Load and weather profiles remain constant over the IPH, whereas PV generation declines over time following system degradation (cf. Table 4).
- Inflation rate of 2% affects energy tariffs (except for FiTs), as well as operating (*opex*) and replacement (*repex*) costs. Moreover, future cash flows are discounted with a real discount rate of 2%, which results in a nominal discount rate of 4.04%.
- The carbon intensity of the German electricity generation mix decreases over time at an annual rate ($carbon\_emissions\_dec$) of 9%.[23]

4 Modeling approach

The modeling approach consists of three main steps.

- **1 - Selection of typical periods**. In order to reduce computational time, an 8-day typical period for each of the four meteorological seasons (s) of the year is selected (cf. Appendix E for details).
- **2 - Techno-economic model: Operation module**. The flows of energy between the HES components are optimized in a 15 min resolution. More specifically, the objective function represents the minimization of total energy costs consisting of volumetric and capacity charges, while technical constraints and limits set by the DSO are respected. A rolling horizon approach is implemented: optimizations are carried out over a 48

[23] This is approx. in line with the IEA's projections of future carbon intensity of electricity generation in the European Union [67].

h optimization horizon (oh) and with a 24 h overlap between each optimization. Only those optimizations within the same season are chained to one another, meaning that the rolling horizon is implemented separately within each 8-day typical period (i.e., each "typical season" s). At the beginning and at the end of each s, standard initial conditions are set for storage systems, and demand peaks are reset to 0. Overall, 28 optimizations (i.e., 7 optimizations for each s) are run, obtaining the optimized energy dispatch over four 8-day typical periods.The Appendix F.1 provides a detailed description of the variables, equations and objective function of the operational optimization model.

- **3 - Techno-economic model: Investment module**. The optimized energy dispatch resulting from the operation module is simulated over the 20-year IPH, accounting for PV output degradation and BES capacity fade. In order to simulate the latter, the model employs the System Advisory Model (SAM, version 2021.12.2) [65] via its Python package PySAM (version 3.0.0) [68].[24] Such a technical simulation outputs the energy flows over the IPH, as well as the corresponding (non-)coincident demand and injection peaks. Accordingly, the financial performance in terms of discounted cash flow (DCF) is calculated, taking into account system costs, inflation and taxation. Total CO_2 emissions over the IPH are derived from 20-year energy flows and their estimated carbon intensity. The Appendix F.2 provides a detailed description of the investment simulation model.

5 Results

This section reports the main results of the financial assessment, grid load, coincident peaks and CO_2 emissions. These results represent the output of 20-year techno-economic simulations, covering all the HESs and the regulatory scenarios under consideration.

5.1 Financial assessment

Table 7 shows the financial performance of each alternative HES in terms of the discounted cash flow of system (i.e., Capex, Opex, Repex) and energy costs (incl. network charges), across the 5 regulatory scenarios, and under a mixed taxation regime.[25]In the case of the BAU scenario, the HES with a 15 kW_p stand-alone PV and a gas heating system (hereinafter GB-15-0[26]) was found to be the best option with a DCF of € 51,237. This value corresponds to a DCF reduction of approx. 7.8% compared to GB-0-0 (hereinafter "reference HES"). This is due

[24]In the case of a HES without BES, PySAM is not run.

[25]This refers to a treatment of VAT involving a mix of the regular regime and the small-business regime. See Equation F.41 in the Appendix for details)

[26]The composition of the HES is abbreviated, in this case GB stands for the gas boiler as opposed to the HP, 15 stands for the kW_p of the PV system, whereas 0 stands for the capacity (in kWh) of the BES system.

Table 7: Discounted cash flow of total costs (€)

		Gas heating					Heat pump				
		Battery energy storage (kWh)					Battery energy storage (kWh)				
Scenario	PV (kWp)	0.0	3.3	6.7	10.0	13.3	0.0	3.3	6.7	10.0	13.3
BAU	0	55,557	-	-	-	-	64,029	-	-	-	-
	5	53,898	57,487	57,283	57,455	57,137	59,425	63,403	63,480	64,219	64,108
	7.5	53,079	56,673	56,365	56,422	55,945	58,133	61,958	61,801	61,979	61,362
	9.9	52,096	55,663	55,254	55,247	54,731	56,884	60,627	60,358	60,158	59,649
	15	51,237	54,671	54,095	54,098	53,484	55,582	59,223	58,734	58,586	57,888
BAU_dyn	0	55,406	60,908	61,823	62,930	63,068	64,408	69,968	70,862	71,956	72,071
	5	55,899	59,365	58,956	58,537	58,536	60,833	64,676	64,650	65,251	65,319
	7.5	56,411	59,787	59,508	59,412	58,706	60,616	64,401	63,875	63,910	63,689
	9.9	56,732	60,091	59,436	58,972	58,841	60,601	64,230	63,457	63,338	62,450
	15	58,227	61,493	61,055	60,429	60,021	61,637	64,974	64,189	63,911	63,273
CC_ref	0	55,494	58,387	58,781	59,592	59,783	62,710	65,667	66,123	66,877	67,069
	5	55,093	57,091	56,979	57,306	57,288	59,883	62,418	62,460	63,515	63,216
	7.5	54,346	56,367	56,104	56,266	56,138	58,750	61,282	61,178	61,467	61,091
	9.9	53,372	55,476	55,170	55,418	55,167	57,557	59,935	59,904	60,200	59,529
	15	52,435	55,189	55,075	55,414	54,469	56,245	59,132	58,950	59,251	58,460
Ene_ref	0	53,916	59,527	60,578	61,133	60,866	54,444	59,983	61,137	61,646	61,360
	5	53,978	58,529	59,015	59,243	59,207	53,076	57,848	58,560	59,038	59,070
	7.5	53,312	57,818	58,183	58,304	58,104	52,166	56,914	57,318	57,884	57,346
	9.9	52,403	56,843	57,072	57,192	57,015	51,110	55,688	56,046	56,235	56,002
	15	51,132	55,519	55,693	55,844	55,640	49,690	54,156	54,462	54,528	54,352
CC&Ene_ref	0	53,854	57,028	57,261	57,860	57,882	53,047	56,279	57,229	58,142	57,930
	5	55,173	58,326	58,639	58,788	59,090	53,493	56,725	57,318	58,345	58,182
	7.5	54,579	57,772	58,193	58,242	57,940	52,811	56,037	56,595	56,999	56,997
	9.9	53,679	56,950	57,100	57,686	57,257	51,795	55,117	55,366	55,718	55,443
	15	52,329	56,127	56,929	57,361	57,009	50,387	54,002	54,688	55,209	54,728

to the fact that the economies of scale more than offset the impact of the lower FiT and self-consumption share of the 15 kW_p PV in comparison to smaller PV systems. BES-coupled PV performed worse than stand-alone systems, but large PV coupled with large BES (e.g., GB-15-13.3) were relatively profitable compared to the reference HES. Turning to the HESs with the electrical heat pump, the DCF of HP-0-0 was clearly one of the worst HESs with a value of € 64,029 (+15.2% with respect to the reference HES). This is unsurprising, given the comparatively high investment costs of the HP and the volumetric rates for heating electricity, which were only partially offset by the high efficiency of this heating system. The coupling of PV improved the financial performance of the HP, as electricity costs were strongly reduced through PV self-consumption, achieving a DCF of to € 55,582 in the case of HP-15-0, which is comparable to the reference HES. Finally, also in the case of HP-based heating, the additional coupling of BES systems appeared to worsen the financial performance of PV systems.

In the case of the *BAU_dyn* scenario, all HESs (excl. the reference HES) performed worse in terms of DCF than in the *BAU* scenario (cf. Table 7). In the case of a HES with PV, this was mostly due to the lower export rate, which, in spite of inflation, reached average values over the 20-year period below 5 ct/kWh, i.e., well below the guaranteed FiTs in the *BAU* scenario (cf. Fig. 3). The increase in the average export rate was trivial even for large BES coupled with small PV (i.e., up to 5.25 ct/kWh). Similarly, the adoption of BES

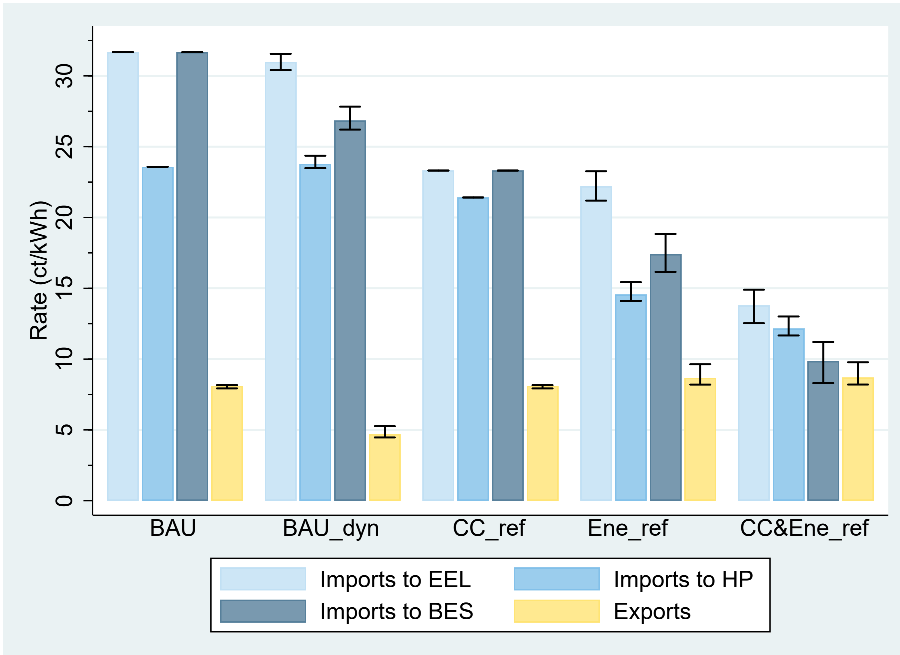

Figure 3: 20-year average of withdrawal (import) and feed-in (export) rates (mean and range of HES-specific values, excl. stand-alone BES systems)

reduced the 20-year average price of imports to the exogenous electrical load[27] (hereinafter EEL) only by up to 3.2% (from 31.43 ct/kWh to 30.41 ct/kWh) (cf. Fig. 3). As a result, the reference system was found to perform best in this scenario, followed closely by HESs with a gas system and a small PV system, especially GB-5-0. In other words, in contrast to the *BAU* scenario, there is no incentive to maximize PV system size (cf. Table 7). Moreover, while the dynamic component slightly lowered the average electricity rate for the EEL in comparison to the *BAU* flat rate, it increased the average rate of HP electricity by up to 3.3% (in the case of HP-0-0) (cf. Fig. 3), resulting in an even worse financial performance of the HP in this second scenario (cf. Table 7). This could be caused by the fact that the HP consumes electricity mostly during winter months, when wholesale electricity prices tend to be higher. The additional adoption of PV improves the performance of HP-based HESs, but the combination of low export rates and high rates for heating electricity resulted in significantly higher DCF compared to the reference system (e.g., +11.2% in the case of HP-15-0).

In the *CC_ref* scenario, GB-15-0 was again the most profitable HES (cf. Table 7). However, while the reference system was substantially unaffected by the

[27] I.e, the synthetic electrical load generated by the LPG, which, in contrast to the HP load, cannot be shifted.

introduction of demand charges,[28] GB-15-0 had a higher DCF (+2.3%) than in the *BAU* case. This was mainly due to the fact that the majority of the expenditure on demand charges could not be avoided through PV self-consumption.[29] With BES, demand and injection peaks were shaved significantly (cf. Section 5.2). However, the additional savings resulting from coincident demand peak shaving were partly offset by the fact that feed-in peaks exceeded demand peaks, meaning that injection charges were levied. Turning to the HESs with HP, HP-0-0 clearly improved its performance in comparison to the *BAU* scenario. This was due to cheaper (-9.2%) volumetric rates, which were not compensated by additional capacity charges, because HP peaks could be easily shaved. However, stand-alone HP heating was still significantly more expensive in terms of DCF than gas-based heating (+13%), and the performance of HP-PV systems even deteriorated in comparison to the *BAU* scenario as a result of lower self-consumption savings.

Turning to the reference system in the *Ene_ref* scenario (cf. Table 7), the reduction in average power volumetric rates more than offset the increase in gas price, resulting in a lower DCF (-3%). However, large stand-alone PV remained superior because the 20-year average export rates achieved values of approx. 8.5 ct/kWh (cf. Fig. 3). This was due to the energy reform, which boosted the earnings from exporting electricity at real-time market prices. Given the higher variability of dynamic prices (cf. Fig. 1), the coupling of BES improved the level of both feed-in revenue and grid savings. However, this was insufficient to make the coupling of BES financially attractive and DCF values were still above € 55,000, due to a drop in the value of self-consumption because of lower import rates following the abolition of surcharges and the electricity tax. The most important shift in this scenario concerns HP-based HESs. As a result of the sharp decrease in average HP electricity rates in comparison to the *BAU* scenario (-34.6%, cf. Fig. 3), HP-0-0 achieved a DCF comparable to GB-0-0 (i.e., approx. € 54,000). Given the increased potential for self-consumption, the additional adoption of a PV system further improved the financial performance of the HES up to a DCF of € 49,690, which was the best financial result for all HESs and scenarios. Finally, the adoption of a complete HP-PV-BES system also resulted in significantly lower DCF values (approx. € 54,000, in the case of a 15 kW_p PV), which interestingly did not vary much depending on BES size.

In the last regulatory scenario *CC&Ene_ref* shown in Table 7, the profitability of the reference system was again (by design) unaffected by the introduction of capacity charges, whereas stand-alone PV systems with GBs experienced an increase in DCF due to a reduction in self-consumption savings as a result of largely non-bypassable demand charges (similar to the *CC_ref* case). BES was used both for energy arbitrage (similar to *Ene_ref* case) and peak shaving (similar to *CC_ref* case), but the performance of PV-coupled batteries did not appear

[28] The levels of such charges were designed to have a neutral impact on standard consumers (cf. Section 3.2.2).

[29] On the contrary, coincident feed-in charges were never levied, as a negligible level of curtailment (< 2 kWh per year) was sufficient to avoid feed-in peaks exceeding annual coincident demand peak in the case of GB-15-0.

to improve compared to the two previous scenarios. On the one hand, the reduction in capacity charges did not match the lack of savings from volumetric network charges compared to the *Ene_ref* case. On the other hand, the earnings from arbitrage did not offset (or surpass significantly) the increase in gas and battery replacement[30] costs compared to the *CC_ref* case. Turning to HP-0-0, the average volumetric rates fell by 44.8% compared to the *BAU* scenario (cf. Fig. 3), while the level of demand charges did not increase thanks to peak shaving (similar to the *CC_ref* scenario). This implies that HP-0-0 performed better than the reference system (only) in this last regulatory scenario, with a DCF of € 53,047, which corresponds to a decrease of -17.2% in comparison to HP-0-0 and of -4.5% in comparison to GB-0-0 in the *BAU* case. Once again, the adoption of a stand-alone PV improved the financial performance of the HP-based HES. Overall, HP-15-0 performed best with a DCF of € 50,387.

This section has shown how the financial results for BES systems (especially stand-alone ones) across all regulatory scenarios, independent of battery capacity, were significantly inferior to stand-alone PV. However, BES coupling is the rule nowadays rather than the exception among residential PV adopters in Germany,[31] which is why the next section focuses on the different operational strategies of batteries and their impacts.

5.2 Grid load and feed-in

Fig. 4 shows the input profiles and the (net) grid load profiles (i.e., the withdrawal or feed-in of electricity from or to the grid, respectively) over a 2-day period in winter, for three selected HESs and for each scenario. The input data (upper left panel) are characterized by a rather constant heat load with a few peaks due to DHW demand, an EEL with a coincident peak of approx. 10.3 kW and non-coincident peak of approx 4.4 kW, as well as a low level of PV generation. In the case of the reference system (GB-0-0), the grid load would correspond to the EEL in any kind of scenario.

In the case of the HP in the *BAU* scenario, the coincident peak increased to 13.1 kWp, as the DSO limits on HP electricity withdrawal did not fully match critical load periods. Given the low PV generation, the additional PV and even the BES had a negligible impact on load shape, and no effect at all on coincident peak shaving.

In the *BAU_dyn* scenario, the coincident peak with HP-0-0 and HP-15-0 was reduced to 10.3 kW, as a result of the correlation between high volumetric power rates and critical load periods. The electricity withdrawal increased when power rates were cheaper, which meant that the HP worked more during the night and more of its electrical load was shifted.[32] With the 13.3 kWh BES,

[30] In the last two scenarios, batteries were used more intensively, which is why replacements were necessary more often and sooner.

[31] The potential reasons for this trend are discussed in Section 6.

[32] This implies a loss in efficiency, because of longer heat storage (i.e., more losses through self-discharge) and because of increased HP operation during colder hours (i.e., lower COP). However, the increase in power consumption of the stand-alone HP over the entire simulation

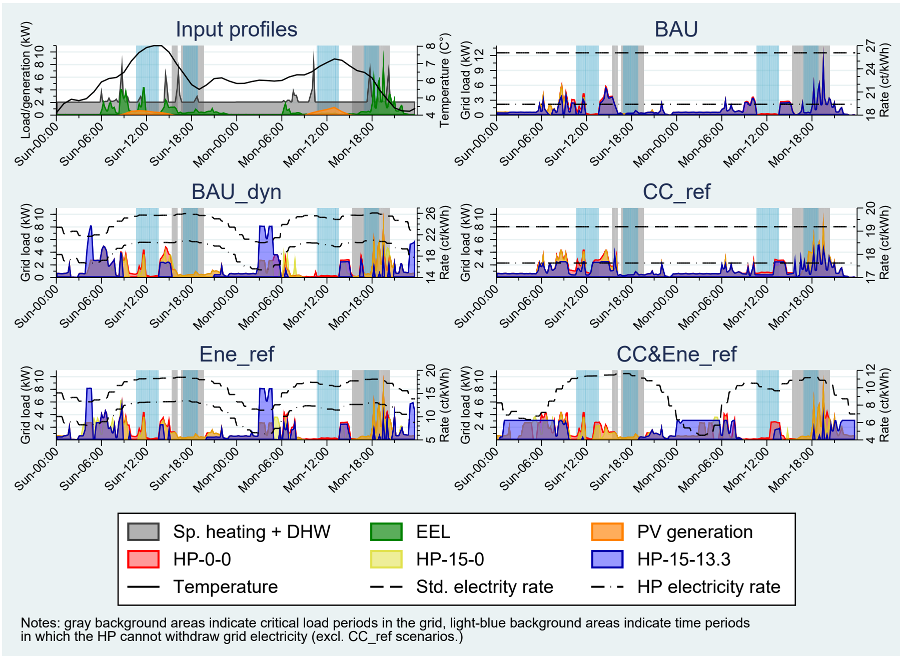

Figure 4: Example of input data and output grid load for selected HESs and over a 2-day winter period

the coincident demand peak dropped to 5.3 kW, and during a large part of the high-cost periods, no electricity was imported. On the other hand, large quantities of electricity were imported by the BES during low-cost periods, resulting in multiple occurrences of non-coincident demand above 8 kW. This finding is consistent with some of the findings in the literature on dynamic prices: while this high demand occurs during off-peak periods, if many prosumers responded simultaneously to the same market signals (i.e., low electricity prices), the resulting aggregated demand could cause new critical load periods in the distribution grid.[33]

In the *CC_ref* scenario, the BES was used less intensively as it was not charged through the grid. Battery as well as HP operation were optimized to reduce both coincident and non-coincident peaks: to 5.31 kW and 2.61 kW, respectively. However, the incentives in this scenario resulted in multiple occurrences of coincident demand above 5 kW, as the demand charge is levied only once on the highest monthly peak.

period was rather modest when compared to the *BAU* scenario (approx. 2.2% at most, i.e., in the *Ene_ref* scenario). In contrast, in the *CC_ref*, the HP consumption was reduced by approx. -1.3%, as no restriction on HP electricity withdrawal allowed for frequent operation during warmer hours outside of critical load periods and shorter storage times.

[33]However, the feedback effect on real-time wholesale electricity prices should also be considered.

In the *Ene_ref* scenario, the grid load profile was very similar to the that of the *BAU_dyn* scenario. Minor differences can be detected with respect to the HP operation, as in this scenario the incentive to shift the HP load to low-cost periods was far greater and prevails on the additional decrease in efficiency.

In the *CC&Ene_ref* scenario, the joint effect of the two previous regulatory scenarios is clear, particularly for HP-15-13.3: large quantities of electricity were withdrawn when rates were cheaper, and both coincident and non-coincident peaks were shaved to 5.3 kW (-61.8% compared to the *BAU* scenario) and 3.2 kW, respectively. Moreover, in contrast to the *CC_ref* case, multiple coincident demand peaks were avoided (the second-highest coincident demand was at 2.69 kW), as a result of the correlation between high volumetric rates and critical load periods, making this BES dispatch strategy the most grid-friendly.

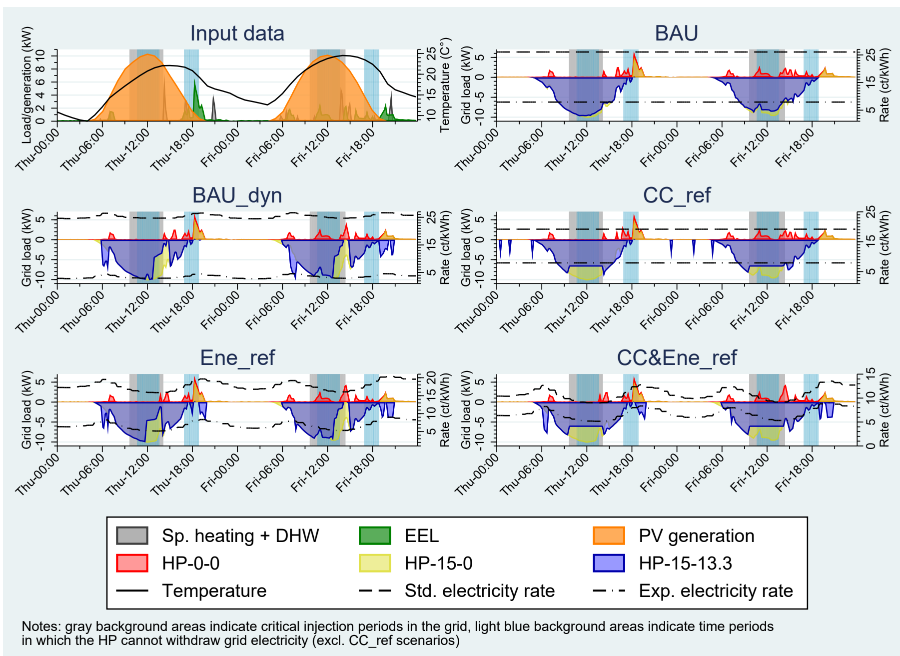

Figure 5: Example of input data and output grid load for selected HESs over a 2-day summer period

Fig. 5 shows the input profiles (upper left panel) and the (net) grid load profile over a 2-day period in summer, for three selected HESs and for each scenario. Unsurprisingly, in contrast to the 2-day winter period, input data are characterized by the absence of space heating load and by high PV generation. Only minimal differences were obvious between scenarios with respect to the grid load of HESs without BES, as the potential for HP load shifting is rather limited. With the 13 kWh BES, the household withdrew no grid electricity in all scenarios, but major differences emerged with respect to the feed-in profile:

only in the scenarios with the *CC_ref* were feed-in peaks shaved, whereas in the scenarios with only dynamic rates, there was no peak reduction. The *CC_ref* scenario diverges from the *CC&Ene_ref* with respect to battery discharging to the grid: in the first scenario, this occurs randomly during off-peak times, whereas in the latter scenario, the battery exported power during hours with high export rates.

Table 8: Coincident demand peak over the 20-year period (kW)

		Gas heating					Heat pump				
		Battery energy storage (kWh)					Battery energy storage (kWh)				
Scenario	PV (kWp)	0.0	3.3	6.7	10.0	13.3	0.0	3.3	6.7	10.0	13.3
BAU	0	10.3	-	-	-	-	13.9	-	-	-	-
	5	10.3	10.3	10.3	10.3	10.3	13.9	13.9	13.9	13.9	13.9
	7.5	10.3	10.3	10.3	10.3	10.3	13.9	13.9	13.9	13.9	13.9
	9.9	10.3	10.2	10.2	10.2	10.2	13.9	13.9	13.9	13.8	13.9
	15	10.3	10.1	10.1	10.1	10.0	13.9	11.7	10.3	8.9	13.9
BAU_dyn	0	10.3	10.3	8.2	5.6	5.3	10.3	10.3	6.8	5.3	5.3
	5	10.3	10.3	8.2	5.6	5.3	10.3	10.3	10.3	6.2	5.3
	7.5	10.3	10.3	8.2	5.6	5.3	10.3	10.3	7.3	5.3	5.3
	9.9	10.3	10.3	8.2	5.6	5.3	10.3	10.3	7.6	5.3	5.3
	15	10.3	10.3	8.2	5.6	5.3	10.3	10.3	10.3	5.3	5.3
CC_ref	0	10.3	7.3	6.3	5.3	5.3	10.3	7.3	6.3	5.3	5.3
	5	10.3	7.3	6.3	5.3	5.3	10.3	7.3	6.3	5.3	5.3
	7.5	10.3	7.3	6.3	5.3	5.3	10.3	7.3	6.3	5.3	5.3
	9.9	10.3	7.3	6.3	5.3	5.3	10.3	7.3	6.3	5.3	5.3
	15	10.3	7.3	6.3	5.3	5.3	10.3	7.3	6.3	5.3	5.3
Ene_ref	0	10.3	10.3	8.9	6.1	5.3	10.3	10.3	6.3	5.9	5.3
	5	10.3	10.3	8.9	6.1	5.3	10.3	10.3	6.8	5.3	5.3
	7.5	10.3	10.3	8.9	6.1	5.3	10.3	10.3	10.3	5.3	5.3
	9.9	10.3	10.3	8.9	6.1	5.3	10.3	10.3	10.3	6.0	5.3
	15	10.3	10.3	8.9	6.1	5.3	10.3	10.3	10.3	6.4	5.3
CC&Ene_ref	0	10.3	7.6	6.3	5.3	5.3	10.3	7.6	6.3	5.3	5.3
	5	10.3	7.8	6.3	5.3	5.3	10.3	7.6	6.3	5.3	5.3
	7.5	10.3	8.1	6.3	5.3	5.3	10.3	7.7	6.3	5.3	5.3
	9.9	10.3	8.4	6.5	5.3	5.3	10.3	7.7	6.3	5.3	5.3
	15	10.3	8.7	6.8	5.3	5.3	10.3	7.7	6.3	5.3	5.3

Finally, coincident peaks for all HESs over the entire 20-year IPH were investigated. Table 8 shows how in the *BAU* scenario, maximum coincident demand was rather independent of the HES, and the adoption of the HP generally worsened this result. A few deviations occurred randomly (most notably in the case of HP-15-10), as there were incentives to either avoid or to incur such peaks. In the scenarios *BAU_dyn* and *Ene_ref*, large BES brought about large coincident peak reductions because of the aforementioned correlation between high-cost and critical load periods. As was expected, the most consistent peak shaving occurred in the scenarios *CC&Ene_ref* and especially in *CC_ref*. Some differences between these two scenarios occurred in the case of the smaller batteries, meaning that a trade-off between peak minimization and energy arbitrage emerged when BES capacity was limited.

Table 9 shows how the maximum coincident PV feed-in in the *BAU* scenario

Table 9: Coincident injection peak over the 20-year period (kW)

		Gas heating					Heat pump				
		Battery energy storage (kWh)					Battery energy storage (kWh)				
Scenario	PV (kWp)	0.0	3.3	6.7	10.0	13.3	0.0	3.3	6.7	10.0	13.3
BAU	0	0.0	-	-	-	-	0.0	-	-	-	-
	5	3.3	3.1	2.9	2.7	2.6	3.3	3.2	3.3	3.1	3.2
	7.5	5.1	4.9	4.7	4.5	4.5	5.0	4.8	5.0	4.8	4.8
	9.9	6.9	6.6	6.4	6.3	6.2	6.7	6.5	6.6	6.5	6.5
	15	10.5	10.3	10.1	9.9	9.9	10.2	10.1	10.1	10.2	10.0
BAU_dyn	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	5	3.3	3.3	3.3	3.5	3.5	3.3	3.3	3.3	3.3	3.1
	7.5	5.1	5.1	5.1	5.2	5.2	5.0	5.2	5.3	5.3	5.0
	9.9	6.9	6.9	6.9	6.9	6.9	6.7	6.9	6.9	6.9	6.9
	15	10.5	10.5	10.5	10.5	10.5	10.2	10.5	10.5	10.5	10.5
CC_ref	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	5	3.3	3.1	2.9	2.7	2.7	3.3	3.3	3.3	3.3	3.3
	7.5	5.1	4.9	4.8	4.5	4.5	5.0	5.0	5.0	5.0	5.0
	9.9	6.9	6.6	6.1	5.3	5.3	6.7	6.7	6.3	5.3	5.3
	15	10.3	9.0	8.6	8.0	7.4	10.2	8.6	8.0	7.4	6.7
Ene_ref	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	5	3.3	3.3	3.3	3.3	3.2	3.3	3.3	3.3	3.1	3.1
	7.5	5.1	5.1	5.1	5.1	5.1	5.0	5.0	5.0	5.0	5.0
	9.9	6.9	6.9	6.9	6.9	6.9	6.7	6.7	6.7	6.6	6.6
	15	10.5	10.5	10.5	10.5	10.5	10.2	10.2	10.2	10.1	10.1
CC&Ene_ref	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	5	3.3	3.3	3.3	3.3	3.2	3.3	3.3	3.3	3.2	3.1
	7.5	5.1	5.1	5.1	5.1	5.1	5.0	5.0	5.0	5.0	5.0
	9.9	6.9	6.9	6.3	5.3	5.3	6.7	6.7	6.3	5.3	5.3
	15	10.3	9.0	8.6	8.0	7.4	10.2	8.0	7.4	6.9	6.3

was only marginally reduced through BES coupling (e.g., from 10.5 kW to 9.9 kW in the case of GB-15-13.3). Scenarios *BAU_dyn* and *Ene_ref* performed even more poorly in this regard. Only in the two scenarios with capacity charges were such injection peaks systematically shaved, but this only concerned the larger[34] PV systems, where the maximum generation exceeded the maximum annual coincident demand. Interestingly, of the two scenarios *CC&Ene_ref* appeared to be slightly more effective in peak shaving in some cases, with a reduction of up to 36.8% compared to the *BAU* scenario (in the case of HP-15-13). This was due to the fact that dynamic export rates during high PV generation periods were lower than the FiT of the *CC_ref* scenario, thereby making it comparatively more profitable to curtail feed-in instead of incurring higher injection charges.

[34] Feed-in peak shaving occurs randomly and not as a result of tariff design in the case of the 5-kW- and 7.5-kW-PV systems, as their peak generation is below the maximum coincident demand (cf. Table 8 and Table 9).

5.3 Impact on carbon emissions

The operation[35] of HESs affected CO_2 emissions in both directions: it increased them, as a result of the energy demand of the household both directly (i.e., through the GB) and indirectly (i.e., through grid electricity); and it reduced them, as a result of the export of electricity,[36] which was assumed to displace power generation with a carbon intensity equal to the average carbon intensity of the real-time generation mix. Consumption-related and (negative) avoided emissions over the 20-year IPH were added up (cf. Eq. F.42 in the Appendix), thereby providing total net CO_2 emissions, which are shown in Table 10. In the case of the reference system, the energy demand of the household caused 81.6 t CO_2 emissions over the 20-year period. The additional adoption of PV reduced emissions by up to 64.3% (i.e., down to 29.2 t in the case of a 15 kW_p system). Such outcomes were independent of the regulatory scenario. The reason for this is that load cannot be shifted, while the differences in feed-in remain negligible. The coupling of BES increased the level of PV self-consumption, meaning that both consumption-related and avoided emissions sunk. In the *BAU* scenario, the decrease in consumption-related emissions more than offset the decrease in avoided emissions, which is why net emissions were slightly reduced when a battery was coupled to a PV system. This was due to the fact that the grid electricity is less emission-intensive during periods of high PV generation and feed-in than during periods of battery discharge. There was an increased saving of carbon emissions when moving from the *BAU* scenario to any other scenario. In the case of capacity charges, BES operation was optimized to reduce demand during critical load periods that correlate with emission-intensive generation. In the case of dynamic pricing, energy arbitrage resulted in larger quantities of electricity being fed in during high-cost periods and withdrawn during low-cost periods. In the case of the energy reform, the large variability of dynamic prices reflect the variation in the carbon intensity of the generation mix. For this reason, emissions savings are greater in the *Ene_ref* scenario than in the *BAU_dyn* scenario, as BES is used more intensively for energy arbitrage.[37] However, the largest reduction in emissions in comparison with the *BAU* scenario was achieved in the case of the *CC&Ene_ref* scenario, where both sets of price signals were involved, resulting in additional emissions savings of up to approx. 2.4 t (e.g., in the case of GB-15-13.3).

Looking at the right side of the table, there is a sharp change in color, as CO_2 emissions fell considerably when the gas heating was replaced with the electrical heat pump. In the *BAU* scenario, satisfying the household energy demand through a HES consisting of a stand-alone heat pump caused 30.9 t CO_2 emissions over the IPH, namely a drop of 62.1% when compared to the 81.6 t in the reference system. When moving to the other regulatory scenarios, emis-

[35] Life-cycle emissions of energy technologies were not considered. Only the carbon emissions caused by the household energy demand over the 20-year IPH were considered.

[36] This was generally self-generated PV electricity, but it could also be low-cost, low-carbon, grid electricity, which had previously been imported and stored in the battery.

[37] In other words, the large variability of electricity rates outweighed the additional energy losses due to storage.

sions dropped further: down to 30.1 t (-63.2%) in the case of the *CC&Ene_ref* scenario, in spite of a more energy-intensive operation of the HP as result of dynamic pricing (cf. Section 5.2). The adoption of PV further reduced emissions significantly, and, in the case of the 9.9 kW_p and the 15 kW_p system, emissions reached a negative level, meaning that the house avoided more emissions than it caused. Once again, BES coupling further reduced emissions, most notably in the case of the *CC&Ene_ref* scenario, with additional savings of up to approx. 2.7 t (e.g., in the case of HP-9.9-13.3) compared to the *BAU* scenario.

Table 10: Total net CO_2 emissions (t) over the 20-year period, assuming an annual decrease of 9% in the carbon intensity of the German electricity generation mix

		Gas heating					Heat pump				
		Battery energy storage (kWh)					Battery energy storage (kWh)				
Scenario	PV (kWp)	0.0	3.3	6.7	10.0	13.3	0.0	3.3	6.7	10.0	13.3
BAU	0	81.6	-	-	-	-	30.9	-	-	-	-
	5	64.1	64.0	63.7	63.6	63.6	13.2	12.9	12.7	12.7	12.6
	7.5	55.4	55.3	55.1	55.0	55.0	4.5	4.2	4.0	3.9	3.9
	9.9	47.0	46.9	46.8	46.7	46.7	-3.9	-4.2	-4.4	-4.5	-4.5
	15	29.2	29.1	29.0	29.0	29.0	-21.8	-22.1	-22.2	-22.3	-22.3
BAU_dyn	0	81.6	81.2	80.8	80.4	80.1	30.6	30.1	29.7	29.3	29.0
	5	64.1	63.5	62.9	62.5	62.0	12.9	12.2	11.7	11.3	10.9
	7.5	55.4	54.7	54.2	53.8	53.2	4.2	3.6	3.0	2.6	2.1
	9.9	47.0	46.4	45.8	45.4	44.8	-4.2	-4.8	-5.4	-5.8	-6.4
	15	29.2	28.6	28.1	27.7	27.2	-22.1	-22.7	-23.2	-23.6	-24.1
CC_ref	0	81.6	81.6	81.6	81.6	81.6	30.7	30.7	30.7	30.6	30.7
	5	64.1	64.0	63.7	63.6	63.5	13.2	12.9	12.7	12.5	12.4
	7.5	55.4	55.2	55.1	54.9	54.9	4.5	4.3	3.9	3.7	3.6
	9.9	47.0	46.9	46.7	46.5	46.5	-3.9	-4.2	-4.3	-4.7	-4.8
	15	29.2	29.0	28.8	28.6	28.4	-21.8	-22.0	-22.4	-22.5	-22.6
Ene_ref	0	81.6	80.8	80.1	79.6	79.2	30.5	29.6	28.9	28.4	28.0
	5	64.1	63.4	62.8	62.3	61.8	12.8	12.0	11.4	10.9	10.5
	7.5	55.4	54.7	54.0	53.5	53.0	4.0	3.3	2.7	2.1	1.7
	9.9	47.0	46.3	45.6	45.1	44.6	-4.4	-5.2	-5.8	-6.3	-6.7
	15	29.2	28.5	27.9	27.3	26.8	-22.3	-22.9	-23.5	-24.1	-24.5
CC&Ene_ref	0	81.6	80.9	80.1	79.6	79.3	30.1	29.2	28.6	28.2	27.9
	5	64.1	63.4	62.7	62.1	61.5	12.7	11.9	11.2	10.5	10.0
	7.5	55.4	54.7	53.9	53.2	52.7	4.0	3.2	2.4	1.8	1.1
	9.9	47.0	46.3	45.6	44.9	44.2	-4.5	-5.2	-6.0	-6.6	-7.2
	15	29.2	28.6	27.8	27.2	26.5	-22.2	-22.9	-23.7	-24.3	-24.9

6 Discussion and outlook

The results presented above show how the regulatory framework, which influences households' energy-related decisions, entails a vast range of implications in the context of the energy transition in the residential sector. In the *BAU* scenario,[38] investing in a stand-alone rooftop PV system (as large as possible) and

[38]Namely the status quo until the first half of 2021, after which energy prices soared to unprecedented levels.

a gas condensing boiler appeared to be the best option from a financial perspective, thanks to FiTs, high volumetric electricity rates (i.e., self-consumption savings) and the relatively low natural gas prices. Although large batteries in combination with large PV performed better than the reference HES (i.e., GB without PV and BES), BES coupling reduced the profitability of PV self-generation. Such a negative result contrasts with the rapid uptake of residential BES in recent years. There are several reasons for this divergence. Firstly, although the national promotion scheme for BES adoption was discontinued in 2018, state- and municipal-level programs continued to subsidize investment in BES with grants of up to € 200-300/kWh [69]. KfW (a state-owned bank) also supports investments in PV-BES systems with promotional loans [70].[39] Secondly, such results are based on a large set of technical and economic assumptions, e.g., if households assumed a lower discount rate, or had more optimistic expectations with respect to battery degradation, or more pessimistic expectations with respect to future retail power prices[40] all of this would improve the expected profitability of BES. As a matter of fact, the economic assumptions in this analysis are based on data that predate the recent spike in energy prices, meaning that if current energy market conditions were to stay, this would greatly affect the profitability of HESs.[41] Thirdly, non-monetary factors such as the availability of back-up power or energy autarky aspiration are often mentioned in the literature as drivers for BES adoption. However, it remains unclear to what extent such drivers are important autonomously or are related to perceptions and expectations, which, in turn, may affect profitability.[42] Besides these considerations regarding PV-BES systems, which are extensively discussed in the literature on residential prosumers, the authors consider the most important and novel finding of the status quo scenario to be the joint assessment of the investment in a new heating system: although sector coupling and especially heat pumps are one of the pillars of the energy transition, the gas-based heating system outperformed by far the electrical heat pump, even when the latter made use of cheap, self-generated PV electricity. Therefore, in this status quo scenario, the technology that had the potential to avoid most of the household

[39] Such government-sponsored loans seem to especially favor BES coupling [30].

[40] For instance, if increasing levels of prosumage were to lead to missing revenue for DSOs (i.e., the "utility death spiral"), volumetric network charges would increase independent of inflation considerations. From a game theory perspective, BES adoption might be a rational, financially-driven decision that would, in fact, even reinforce such a negative trend toward increasing retail rates.

[41] In this regard, a sensitivity analysis of the financial results of the *BAU* scenario was conducted, in which the retail rates of electricity and gas at the beginning of 2022 were assumed. This meant that volumetric rates increased approx. by 64% for standard electricity, by 97% for heating electricity, and by 335% for gas, whereas FiTs decreased by approx. 14%. Under such assumptions, the DCF of all HESs grew substantially, yet, in contrast to the *BAU* results, the options with a high level of energy self-sufficiency (with regard to both gas and electricity) stood out as the best. In particular, adopting a HES with the heat pump, the largest PV and the largest BES (i.e., HP-15-13.3) led to a reduction in DCF of 29% (approx. € 28,000) compared to the reference HES.

[42] For instance, is the desire of independence of power suppliers a goal in itself or is it connected to expectations of and risk aversion regarding rising electricity prices?

CO_2 emissions, was significantly inferior from a financial perspective and hence far less likely to be adopted.

In the *BAU_dyn* scenario, a shift to dynamic electricity prices for retail consumers occurred, which is a policy reform that has often been proposed in the literature. It was found that the simple implementation of dynamic pricing worsened the financial performance of both PV and HPs, resulting in the worst results in terms of incentives for carbon emissions reduction.

In contrast, in the *Ene_ref* scenario, a shift to dynamic pricing accompanied by a CO_2-oriented reform of energy taxes and surcharges increased the financial attractiveness of the HP because of low(er) retail electricity prices (especially during times of low-carbon power generation), while maintaining the profitability of residential PV, as a result of higher export rates following the full pricing of CO_2 in the wholesale electricity market.[43] Moreover, dynamic pricing led to a moderate, additional decrease in carbon emissions, as well as to a reduction in coincident demand peaks through the market-oriented operation of HPs and batteries. Although dynamic pricing improved the level of grid friendliness of the operation of BES and HPs in terms of coincident demand, it resulted in new high demand peaks during non-critical periods that could become critical if many prosumers were to follow the same market signals. At the same time, the price signals of this scenario failed to induce the shaving of coincident injection peaks.

In the *CC_ref* scenario, the shift from volumetric to capacity-based network charges achieved superior results in terms of grid integration, in that not only coincident demand, but also non-coincident demand and coincident injection peaks were shaved. However, this regulatory scenario delivered poor results in terms of incentivising the adoption of the HP over the GB, as electricity volumetric rates did not fall sufficiently.

Finally, the *CC&Ene_ref* scenario combined the positive effects of both reforms in terms of CO_2 reduction and grid integration, as the trade-off between the two objectives was very limited. In fact, the combined effect of the two reforms even increased the degree of grid friendliness compared to the simple *CC_ref* scenario, as the number of coincident demand peaks diminished due to the correlation between critical load periods and high electricity prices.

In this study, the evaluation of regulatory scenarios went beyond a mere household perspective, but the methodological approach did not allow for an all-encompassing, macro-level assessment. The scope of this analysis was limited to understanding how alternative sets of price signals shape the financially optimal adoption and operation of a given set of energy technologies in a given household living in a given house[44] at a given location. The system perspective

[43] Such a national-level pricing mechanism would go beyond the ETS and would only apply to the demand-side of the German electricity market, in order to prevent carbon leakage to other countries (cf. Section 3.2.3). Of course, a uniform and global carbon pricing mechanism in every sector of the economy would be ideal. However, this is politically complex, and is far beyond the scope of this paper.

[44] Assumptions on size, energy efficiency, and level of refurbishment of the building determine crucial input data such as heat demand, investment costs, and suitable heating technologies.

was incorporated by examining the resulting household grid load in relation to the real-time network conditions and the real-time carbon intensity of grid electricity. A broader system-level evaluation would need to consider a heterogeneous set of consumer profiles, buildings, and locations, estimate technology diffusion and households' grid load across regulatory scenarios, as well as assess feedback effects of such aggregate households' decisions on wholesale electricity prices, on regulated components (e.g., network charges), and on grid operation. Furthermore, while this paper presented a reform of network charges that aims to improve the financial sustainability, the cost reflectivity and, to some extent, the distributional fairness of network charges, it did not measure how the different regulatory scenarios perform in this respect. Overall, the limitations of such a micro-level approach indicate the need for further research on such macro-level impacts.

Another set of limitations regards the high uncertainty concerning future energy prices and carbon intensity, including the future market design of the electricity sector. However, the authors made assumptions based on their current state of knowledge, especially when considering the assumptions that real-world households might make when deciding on energy technologies. The optimization approach is a simplification of a real-world household, as the optimal operation based on a smart energy system manager and a perfect foresight of load, weather, and power prices over a 48 h horizon may result in overoptimistic findings. Such an optimistic bias was partially counteracted in this study by assuming an exogenous electrical load profile, which cannot be adapted to dynamic prices, critical peak pricing or PV generation, thereby favoring a potential overestimation of costs (especially in the *CC&Ene_ref* scenario). Overall, such biases tend to overestimate the relative profitability of BES, while penalizing stand-alone PV.[45] The potential for demand response, besides the HP controllable load, is another aspect that deserves further research. Finally, as in the case of residential BES systems, other policy-driven factors affect the adoption of heating technologies, such as national- and regional-level subsidies, building mandates and promotional loans, which also deserve further investigation.

7 Conclusions

In this study, five regulatory scenarios were devised as alternatives to the status quo regulatory framework for residential energy consumers in Germany. In particular, this paper proposed two policy reforms that aim to (i) improve the financial sustainability and cost reflectivity of network charges; (ii) promote efficient grid operation; (iii) incorporate the real-time carbon emission intensity into dynamic retail energy prices, while removing other energy-specific surcharges and taxes. The study focused on the case of a 4-person household living in a single-family house, and evaluated the investment in a new HES consisting of PV, BES, and either a GB or a HP. By means of a techno-economic optimization

[45] On the other hand, the relatively low temporal resolution of the PV generation profile might result in the overestimation of PV self-consumption rates.

and simulation model, the profitability and financially-driven optimal operation of such alternative HESs were assessed across the five regulatory scenarios.

In the *CC&Ene_ref* scenario, the implementation of both policy reforms has shown how aligning the incentive structure for households, as energy consumers and power grid users, with a more system-oriented perspective may be crucial for (i) a more cost-efficient and effective decarbonization of the residential sector; (ii) a more cost-efficient operation of and investment in the network infrastructure. On the one hand, the energy reform incentivized the adoption of the HP, as opposed to the GB, bringing about very substantial savings in terms of carbon emissions without increasing the costs for the household. At the same time, PV profitability was not penalized by such a reform. For these reasons, a more cost-efficient and effective decarbonization is expected in this scenario. On the other hand, the combination of both reforms incentivized a grid-friendly operation in terms of reducing the level and frequency of coincident demand and coincident feed-in peaks. At an aggregated level, such a grid-oriented operation of HPs and especially BES is expected to reduce the marginal operational and investment costs of the grid.

The low financial attractiveness of the HP under the status quo regulatory framework could call into question the consistency of the climate neutrality target by 2045 set by Germany's policy makers, as the installation of gas boilers involves lock-in periods of 20-25 years. In 2021, the sales of gas boilers exceeded the sales of heat pumps by a factor of more than four[71]. Even in newly built houses, the share of gas-fired heating systems was still approx. 26% [72]. A regulatory shift is essential to avoid a failed decarbonization of the residential sector. Moreover, an earlier and consistent shift from gas-based residential heating to an electricity-based system would have alleviated the energy crisis that has been affecting Germany since the second part of 2021, and that has worsened as a result of the Russo–Ukrainian War.

A full assessment of the cost efficiency of PV prosumage, of the general cost efficiency of PV generation at Germany's latitude, or of the optimal level of decentralization of the power system was beyond the scope of this paper. According to German policy makers, rooftop PV shall become one of the most relevant parts of the German generation mix. The status quo regulatory framework for residential PV and BES has favored[46] the diffusion of these technologies among homeowners living in single-family houses who can take advantage of the indirect subsidies for self-consumption, which is why this paper focused on this segment of the residential sector. However, PV systems ought to be installed on rooftops independent of the ownership status of the underlying dwellings. Indeed, PV installations on apartment buildings may be even superior in terms of cost efficiency compared to single-family houses, because of larger rooftops (i.e., economies of scale) and potentially higher self-consumption levels.[47] While

[46]The recent abolition of the EEG surcharge is reshaping the regulatory framework, but it goes only partially in the direction of the energy reform proposed in this paper. Neither a CO_2-oriented reform has fully replaced this financing mechanism, nor have dynamic retail power prices been implemented.

[47]In multi-story apartment buildings, a higher electricity demand per m^2 of rooftop surface

such a fundamental aspect was not explicitly addressed in this analysis, a regulatory shift to a more market-oriented approach for retail energy tariffs, as in the case of the *CC&Ene_ref* scenario, would likely benefit the economics of residential PV in the case of tenant-occupied apartment buildings, both for the PV operator and the potential electricity consumers (i.e., tenants). The first could benefit from the higher wholesale electricity rates (following the energy reform presented in this paper), which are independent of PV size (in contrast to FiTs) and could even establish a special rate for consumers within the building. The latter, even without a special rate, could try to increase consumption from the local PV, as such local consumers would avoid paying the concession fee.[48] The same regulatory shift could benefit homeowners (or building owners) who do not want to invest directly in PV, as they could let third-party companies install and operate PV systems on their rooftop, possibly in exchange for a lease payment. The diffusion of such a business model would imply that specialized companies would mostly operate PV systems, meaning that further cost efficiency gains might be expected, as a result of economies of scale and expertise. Overall, a regulatory shift in this direction may create a level playing field between homeowners and tenants, independent of the opportunity, capability or inclination to take an "active" part in the energy transition. Regardless of general cost efficiency and distributional implications, in the German public discourse, households' self-sufficiency aspiration seems to have become a core value of citizen involvement in the energy transition. A new regulatory framework may overturn such narratives of a low-carbon, decentralized energy system being reliant on self-sufficiency, and shift public attention to the need for a grid and market integration of all actors - as grid users, energy consumers and prosumers.

Appendix A Status quo energy tariffs

A.1 *BAU* tariffs

In order to make an unbiased[49] assumption with regard to electricity rates for retail consumers in Germany, several offers from power suppliers were considered, as retail electricity bills vary significantly in terms of fixed and variable (i.e., volumetric, kWh-based) components, as well as potential bonuses for new contracts. A website [73] that compares energy providers, was used to find the best tariffs for the selected location for a 12-month delivery period. When signing a new delivery contract, households often receive a bonus for new customers,

may be expected.

[48] Under the current regulatory framework on local PV electricity for tenants (i.e., *Mieterstrom*), PV operators can enter a contract with tenants setting a price below the default tariff of the local default supplier. On this local electrical supply, only the VAT and the EEG surcharge are levied.

[49] In the literature on prosumers, assumptions regarding electricity rates rarely distinguish between fixed and variable components, although this is crucial for the correct assessment of savings from self-consumption

which significantly reduces the bill for the first year.[50] Moreover, electricity suppliers adapt their fixed and variable charges according to the level of estimated annual consumption. Therefore, offers for a low- and a high-consumption level (1000 kWh and 5000 kWh, respectively) were taken into consideration by averaging the estimated annual bill (incl. VAT) of the five cheapest offers, including a bonus for new clients, and the five cheapest ones without a bonus. Subsequently, the volumetric rate (cf. Eq. A.1) that equalizes the fixed component for both levels of consumption (cf. Eq. A.2) was derived, obtaining a flat volumetric charge ($rate\_std^{flat}$) of 26.07[51] ct/kWh and a fixed annual charge ($rate\_std^{fixed}$) of € 118.52.

$$rate\_std^{flat} = \frac{(Bill^{1000kWh} - Bill^{5000kWh})}{1000 - 5000} \tag{A.1}$$

$$rate\_std^{fixed} = Bill^{1000kWh} - rate\_std^{flat} \times 1000 = Bill^{5000kWh} - rate\_std^{flat} \times 5000 \tag{A.2}$$

With respect to the electricity consumed by the heat pump, lower retail prices were considered, because in the German context, retail consumers who use electricity for heating can obtain a second electricity meter and benefit from cheaper rates. On the other hand, HPs are subject to a limitation by the DSO in that they cannot withdraw electricity from the grid during certain periods of the day.[52] For the estimation of HP electricity rates, the same approach as above was implemented by retrieving heating electricity tariffs for a low- and high-consumption household (1000 kWh and 5000 kWh, respectively) with and without bonuses and then adjusting them to 2019 prices. A flat volumetric charge ($rate\_hp^{flat}$) of 19.41 ct/kWh and a fixed annual charge ($rate\_hp^{fixed}$) of € 66.46 were calculated. Gas tariffs were also estimated in the same way, but here offers for low- and high-consumption levels were retrieved for 5000 kWh and for 20000 kWh, respectively. A flat volumetric charge ($rate\_hp^{flat}$) of 4.63 ct/kWh and a fixed annual charge ($rate\_hp^{fixed}$) of € 136.69 were derived accordingly. The FiTs for the exported electricity correspond to the values for a PV system installed in January 2021: 8.16 ct/kWh for systems with a nameplate capacity below 10 kW and 7.93 ct/kWh for the largest system considered in this analysis (15 kW_p).

[50] If customers cancel a contract after the first year of delivery, they can aim to obtain a new bonus with a new supplier.

[51] Following the analysis of offers, which were retrieved in the first part of 2021, a lower value amounting to 25.12 ct/kWh was obtained. In order to harmonize such BAU tariffs with the wholesale-market data for 2019, it was assumed that retail tariffs at the beginning of 2021 reflected wholesale prices of the previous year, which is why the non-regulated component of such a flat retail rate was adjusted by applying an increase of approx. 24%. This corresponds to the change in average volume-weighted electricity day-ahead prices between 2020 and 2019 (i.e., from € 29.52/MWh to € 36.64/MWh [19]), resulting in an increase in the final retail rate of approx. 4%.

[52] In accordance with DSO's limitations, in the case of scenarios without reformed network charges (i.e., all of them except *CC_ref* and *CC&Ene_ref*), a constraint was set on the withdrawal of heating electricity during periods between 10:30–13:30 and 17:00–19:00 in the techno-economic model (cf. Appendix F.1, Eq. F.15).

A.2 *BAU_dyn* tariffs

In this scenario, retail power rates include all volumetric regulated price components, which constitute most of volumetric charges in the *BAU* scenario. They were 21.2 ct/kWh and 16.11 ct/kWh (incl. VAT), respectively for standard electricity and heating electricity. The rest of the kWh charge is dynamic and corresponds to the wholesale market price plus VAT, except in the case of negative prices). The export rate corresponds to the wholesale market price independent of PV size. Wholesale market prices correspond to the day-ahead hourly prices for Germany from year 2019. Such data are described in Section 3.2.3.

Appendix B Cross-validation of capacity charges

According to the local DSO (*Westnetz*) data from 2019, grid electricity consumed by standard load profile (SLP) customers (i.e.,*Nicht leistungsgemessene Kunden*) was 12,974,028,800 kWh. The present study assumes that, in line with national-level data [11], only 8.6% of this electricity was used for electric heating, benefiting from a lower volumetric network charge of 1.79 ct/kWh (incl. VAT). The remaining consumption was assumed to be subject to the regular network charge of 6.88 ct/kWh (incl. VAT). Consequently, the revenue from volumetric charges from SLP customers was approx. € 836 million. It was assumed that 4 million SLP customers[53] paid a fixed charge of € 78.18 (incl. VAT), adding up to approx. € 1,148 million in total revenue from both fixed and volumetric network charges.

In order to estimate the revenue from demand charges, firstly the average consumption of standard-use electricity resulting from the aforementioned assumptions was calculated as 2,964 kWh. Secondly, after a brief analysis of several synthetic load profiles, average monthly peak-to-average (PTA) ratios for on-peak and off-peak demand were assumed: namely 9[54] and 15, respectively. Considering the average consumption level (i.e., 2,964 kWh), these PTA ratios resulted in average monthly peaks of 3.05 kW for on-peak demand and 5.08 kW for off-peak demand. Finally, the revenue from demand charges was calculated by multiplying the average demand peaks, the number of months in which the charge would be levied,[55] the respective on- and off-peak charges (namely € 5 and € 2.50, incl. VAT), and the number of SLP customers (4 million). This amounted to approx. € 548 million from on-peak charges and € 609 million from off-peak charges respectively, adding up to approx. € 1,157

[53] The number of connections to the low-voltage grid was 4,159,891.

[54] In this analysis, monthly coincident peaks varied greatly: in the months between April and October critical load periods did not seem to be correlated with typical residential demand peaks, as they occurred in rare instances and in the hours around midday (cf. Table 2). Winter months, in contrast, abounded with critical periods, which were directly linked with residential load patterns. For this reason, winter months tended to have coincident PTA ratios well above 10, whereas in warmer months PTA ratios were sometimes even below one

[55] I.e, 9 in the case of on-peak charges, as no network peak occurred between July and September (see Table 2). In contrast, off-peak demand charges would be levied every month.

million in total revenue from demand charges. To this rough estimate, the revenue from injection charges must be added, which is why the assumed level of capacity charges is considered more than sufficient to match the revenue of the current status quo (i.e., € 1,148 million).

Appendix C *Ene_ref* data

The data on wholesale electricity prices consists of day-ahead hourly prices of the electricity market bidding zone comprising Germany and Luxembourg, which were retrieved from the ENTSOE platform ([74]). The data on EU ETS allowances (i.e., CO_2 price) were retrieved from ([75]). The data on electricity generation by generation type in Germany consist of the "Aggregated generation per type" data in a 15 min resolution, as collected by transmission grid operators and published on the ENTSOE platform [76, 74]. The data on CO_2 emissions of the German electricity mix were published by the German Environmental Agency [18]. Table 11 shows the emission factors,[56] which were derived either directly or indirectly from [18].[57] With respect to the emissions caused by the gas boiler, an emission factor of 201 g CO_2 per each kWh of natural gas was assumed [18].

Table 11: Assumed emission factors by type of generation (g CO_2/kWh)

Hard coal	Lignite	Nat. Gas	Petroleum prod.	Waste	Other
852	1135	409	813	0	795

The data on electricity generation from [74] with the total gross generation from [18] needed to be harmonized. The hourly source-specific generation values were adjusted for a constant factor, by which the sum of each generation type of the first data source[58] (i.e., [74]) equals the annual values published in the second data source (i.e., [18]). After this data set adjustment, the CO_2 intensity of the German electricity mix was estimated in an hourly resolution.[59]

[56] Only carbon emissions directly deriving from electricity generation were considered, whereas life-cycle emissions of power generation technologies were not.

[57] Emission factors of hard coal, lignite and natural gas were published directly in [18] and refer to the year 2019. For the remaining types of non-carbon-free generation, emission factors were derived using the data on source-specific gross electricity generation (in TWh) and their respective CO_2 emissions (in Mt). To reduce rounding up errors, the computed emissions factors were averaged over a 5-year period (2015-2019). The emission factor for "waste" was set to 0, as emissions from municipal waste power plants are not included in the EU ETS [77]. The remaining types of power generation were considered carbon-free, namely: nuclear, biomass, wind, PV and hydroelectric.

[58] Apart from minor discrepancies across sources, ENTSOE data do not cover all power plants and systematically underestimate the actual generation for some energy types (e.g. natural gas) [76].

[59] Such hourly emission factors of the German power mix consider only electricity production occurring in Germany. They do not fully reflect the carbon intensity of electrical consumption, which also depends on international power flows. In the case of Germany, considering

Appendix D Heat pump parameters

Table 12: Temperature-varying maximum output power (kW) and efficiency (COP) of the HP

External (air) temperature (°C)	Flow (water) temperature (°C)			
	35		55	
	kW	COP	kW	COP
-15	5.8	2.5	5.2	1.7
-7	7.2	2.8	6.0	1.7
2	9.4	3.4	8.7	2.3
7	10.8	4.2	9.5	2.7
15	11.4	5.8	10.7	3.3
20	12.0	7.2	10.6	3.8
25	11.0	8.7	7.8	4.3
30	10.8	9.0	8.2	4.8
35	11.2	9.3	8.4	5.5

Appendix E Typical periods

In order to reduce the number of optimizations and, thus, the total computational time of the operation module, an 8-day typical period for each of the meteorological seasons was selected. The aim was to choose a period of 8 consecutive days that best mirrors the seasonal costs of meeting the household's energy demand, as well as the potential revenue from electricity exports to the grid. The selection of typical periods is based on a set of simplifying assumptions:

- The HES consists of a 9.9 kW PV system, a heat pump and no BES system.
- No heat is stored, meaning that heat generation is neither deferred nor optimized.
- The heat pump can be operated simultaneously at 35 °C and 55 °C.

Therefore, a simplified HP load can be derived (cf. Eq. E.1).

$$HP\_load_t = \frac{SpH_t}{COP35_t} + \frac{DHW_t}{COP55_t} \tag{E.1}$$

production-based carbon intensity as a proxy for consumption-based carbon intensity, on average, may lead to a slight overestimation of the latter [78]. However, the German Environmental Agency calculates domestic electrical consumption on the assumption that power imports and exports have the same generation mix and carbon intensity [18]. Therefore, this paper assumes that a real-world implementation of such a national CO_2 pricing mechanism would most likely consider the domestic, production-based carbon intensity.

Dispatch rules are set for PV electricity, according to which it supplies firstly the EEL[60] (see Eq. F.1 and Eq. F.2 in Appendix F.1), secondly supplies the heat pump load (cf. Eq. E.2), and finally is exported to the grid (cf. Eq. E.3).

$$PV_t^{HP} = \begin{cases} HP\_load_t, & \text{if } PV_t^{gen} - PV_t^{EEL} > HP\_load_t \\ PV_t^{gen} - PV_t^{EEL}, & \text{otherwise} \end{cases} \tag{E.2}$$

$$PV_t^{Grid} = PV_t^{gen} - PV_t^{EEL} - PV_t^{HP} \tag{E.3}$$

Therefore, the net kWh-based costs are calculated using the energy rates of the BAU scenario.

$$\begin{aligned} tp\_costs_t = [(EEL_t - PV_t^{EEL}) \times rate\_std_t + (HP\_load_t - PV_t^{HP}) \times rate\_hp_t \\ - PV_t^{Grid} \times rate\_exp_t] \times \frac{1}{kW^{kWh}} \end{aligned} \tag{E.4}$$

Finally, the average net cost of energy over all meteorological seasons, defined as 3-month periods (i.e, December–February, March–May, June–August, September–November), is calculated. Similarly, the average net kWh-based cost of energy for each 8-day period within each season is calculated, after which the period that better replicates the seasonal average was chosen.

Appendix F Techno-economic model

Table 13 shows the time indexes used in the two modules of the techno-economic model, which range from 15 min time steps reflecting the temporal resolution of the operation optimization to annual time steps needed for the cash flow simulation of the investment module.

Table 13: Time indexes of the model

Symbol	Description	Range
y	year within planning horizon	$\{1, 2 ... Y = 20\}$
s	8-day typical period	$\{1, 2 ... S = 4\}$
oh	48 h optimization horizon within s	$\{1, 2 ... OH = 4\}$
t	15 min time step within oh	$\{1, 2 ... T + 1 = 197\}$
ts	15 min time step within s	$\{1, 2 ... TS = 784\}$

[60] The exogenous electrical load, i.e, the synthetic electrical load generated by the LPG, which, in contrast to the HP load, cannot be shifted.

F.1 Operation module

Table 14 provides an overview of the parameters[61] and the variables of the operation module, as well as their respective ranges or, in the case of variables, upper and lower bounds (i.e., model constraints). The following sections describe how the energy dispatch is optimized through the cost minimization of volumetric and capacity charges.

F.1.1 Volumetric charges minimization

This section describes the equations needed to minimize the net volumetric (or kWh-based) charges, i.e., the charges levied on the amount of purchased energy, minus the potential revenue resulting from electricity feed-in.

Equations F.1 and F.2 show how the flow of power from the PV system to the EEL is determined following a simple dispatch rule, i.e., PV generation is used firstly to meet such a demand (cf. Eq. F.1 and F.2).

$$PV_t^{surplus} = \begin{cases} PV_t^{gen} - EEL_t, & \text{if } PV_t^{gen} \geq EEL_t \\ 0, & \text{otherwise} \end{cases} \tag{F.1}$$

$$PV_t^{EEL} = \begin{cases} EEL_t, & \text{if } PV_t^{surplus} > 0 \\ PV_t^{gen}, & \text{otherwise} \end{cases} \tag{F.2}$$

The electricity from the PV system can flow to the load, to the heat pump, to the battery system, to the grid, or be curtailed (cf. Eq. F.3).

$$PV_t^{gen} = PV_t^{EEL} + PV_t^{HP35} + PV_t^{HP55} + PV_t^{BES} + PV_t^{Grid} + PV_t^{Curt} \tag{F.3}$$

In the case of scenarios without demand charges (e.g., BAU), the export of electricity to the grid is capped at 70% of the maximum power of the PV system (cf. Eq. F.4).

$$PV_t^{Grid} + BES_t^{Grid} \leq PV\_pow \times Feed-in^{limit} \tag{F.4}$$

When a heat pump is provided, the heat load profiles for space heating and for DHW are supplied via two heat storage systems (HSs), which contain water at 35 °C and 55 °C, respectively (cf. Eq. F.5 and F.6).

$$SpH_t = HS35_t^{SpH} \tag{F.5}$$

$$DHW_t = HS55_t^{DHW} \tag{F.6}$$

The SoC of the two heat storage systems at the beginning of each s are fixed at given initial values, whereas the SoCs at the beginning of each subsequent oh correspond to the SoCs at the beginning of the overlapping period of the previous optimization (cf. Eq. F.7 and F.9)). Finally, at the end of the s, the storage systems return to their respective initial conditions (cf. (cf. Eq. F.8

[61] Additional system parameters can be found in Tables 4, 5, 6, and 12.

and F.10)). In the remaining time steps, the SoCs are determined by the SoC of the previous time step adjusted for the losses due to self-discharge, as well as by the charge from the heat pump and discharge to the respective heat loads (cf. Eq. F.11 and F.12).

$$HS35\_soc_{1,oh} = \begin{cases} HS35\_soc^{init}, & \text{if } oh = 1 \\ HS35\_soc_{\frac{T}{2}+1,oh-1}, & \text{otherwise} \end{cases} \tag{F.7}$$

$$HS35\_soc_{T+1,OH} = HS35\_soc^{init} \tag{F.8}$$

$$HS55\_soc_{1,oh} = \begin{cases} HS55\_soc^{init}, & \text{if } oh = 1 \\ HS55\_soc_{\frac{T}{2}+1,oh-1}, & \text{otherwise} \end{cases} \tag{F.9}$$

$$HS35\_soc_{T+1,OH} = HS35\_soc^{init} \tag{F.10}$$

$$HS35\_soc_t = \sigma \times (HS35\_soc_{t-1}) + \frac{(HP_{t-1}^{HS35} - HS35_{t-1}^{SpH})}{kW^{kWh}} \tag{F.11}$$

$$HS55\_soc_t = \sigma \times (HS55\_soc_{t-1}) + \frac{(HP_{t-1}^{HS55} - HS55_{t-1}^{DHW})}{kW^{kWh}} \tag{F.12}$$

The flow of power to the heat pump can be supplied by three different sources: the grid, the PV, or the BES. The COP depends on the external air temperature at each given time step (cf. Table 12). Such coefficients determine the efficiency at which electricity is converted into heat at the output water temperatures of 35 °C and 55 °C (cf. Eq. F.13 and Eq. F.14).

$$HP_t^{HS35} = COP35_t \times (Grid_t^{HP35} + PV_t^{HP35} + BES_t^{HP35}) \tag{F.13}$$

$$HP_t^{HS55} = COP55_t \times (Grid_t^{HP55} + PV_t^{HP55} + BES_t^{HP55}) \tag{F.14}$$

In scenarios without demand charges, the local DSO limits the withdrawal of electricity for heating to some specific time slots (cf. Eq. F.15).

$$Grid_t^{HP\_on} = 0 \Rightarrow Grid_t^{HP35} = Grid_t^{HP55} = 0 \tag{F.15}$$

The heat pump cannot operate simultaneously at 35 °C and 55 °C, which is why fictive costs, $HP\_doc_{oh,s}$, are set, by which the simultaneous dual operation of the HP is strongly disincentivized and, therefore, avoided (cf. Eq. F.16).

$$HP\_doc_{oh,s} = \sum_{t=1}^{T} (HP_t^{HS35} \times HP_t^{HS55}) \times 1000 \tag{F.16}$$

In the simulations in which the heating demand is supplied by a gas boiler, there is no storage for space heating, as heat is generated on demand (cf. Eq. F.17).

In contrast, heat storage for DHW is still provided (i.e., Eq. F.6 still holds) to guarantee a minimum level of ready-to-use hot water (cf. Eq. F.18).

$$SpH_t = GB_t^{SpH} \tag{F.17}$$

$$HS55\_soc_t = \sigma \times (HS55\_soc_{t-1}) + \frac{(GB_t^{HS55} - HS55_t^{DHW})}{kW^{kWh}} \tag{F.18}$$

The operation of the gas boiler and its efficiency for heat generation determine the demand for gas (cf. Eq. F.19). Such an efficiency rate is assumed to be constant and equal for both operation modes. The non-simultaneity of space heating and DHW generation is not modeled explicitly, since a relatively limited demand for space heating should be easily shifted without additional costs (given the thermal inertia of the building).[62]

$$Gas_t^{GB} = (GB_t^{SpH} + GB_t^{HS55}) \times \frac{1}{\eta^{gb}} \tag{F.19}$$

When a BES system is provided, the optimization is subject to an additional set of constraints. The BES can be charged with power from the grid or the PV system, but the total charged power at each time step cannot exceed the input power rating of the battery (cf. Eq. F.20).

$$PV_t^{BES} + Grid_t^{BES} \leq BES\_ipow \tag{F.20}$$

The BES can discharge to supply power for the EEL or the heat pump, or to export power to the grid. The total discharged power at each time step cannot exceed the output power rating of the battery (cf. Eq. F.21).

$$BES_t^{EEL} + BES_t^{HP} + BES_t^{EEL} \leq BES\_opow \tag{F.21}$$

The SoC at the beginning of each s is set to BES_soc^{init}, whereas the SoC at the beginning of each subsequent oh corresponds to the SoC at the beginning of the overlapping period of the previous optimization (cf. Eq. F.22). At the end of s, the BES returns to BES_soc^{init} (cf. Eq. F.23). In the remaining time steps, the SoC must equal the previous SoC, plus the electricity charged, minus the electricity discharged. The charging and discharging flows are adjusted for the conversion losses from DC to AC and vice versa, i.e., battery charging and discharging efficiencies (cf. Eq. F.24).

$$BES\_soc_{1,oh} = \begin{cases} BES\_soc^{init}, & \text{if } oh = 1 \\ BES\_soc_{\frac{T}{2}+1,oh-1}, & \text{otherwise} \end{cases} \tag{F.22}$$

$$BES\_soc_{T+1,OH} = BES\_soc^{init} \tag{F.23}$$

[62]In the case of a heat pump, in contrast, heat storage is required to shift a major share of the heat load, as a result of operation optimization with respect to variable COP, PV generation, dynamic electricity prices, and DSO limits.

$$BES\_soc_t = BES\_soc_{t-1} + \frac{(PV_{t-1}^{BES} + Grid_{t-1}^{BES})}{kW^{kWh}} \times \eta^{cha}$$
$$-\frac{(BES_{t-1}^{EEL} + BES_{t-1}^{HP} + BES_{t-1}^{EEL})}{kW^{kWh}} \times \frac{1}{\eta^{dis}} \text{ for } 1 < t \leq T+1 \tag{F.24}$$

Finally, the net kWh-based costs resulting from volumetric charges, which depend on the electricity and gas flows and their respective rates, are defined (cf. Eq. F.25).

$$kWh\_costs_{oh,s} = \sum_{t=1}^{T}[(Grid_{t,oh,s}^{EEL} + Grid_{t,oh,s}^{BES}) \times rate\_std_{t,oh,s} + (Grid_{t,oh,s}^{HP35}$$
$$+Grid_{t,oh,s}^{HP55}) \times rate\_hp_{t,oh,s} - (PV_{t,oh,s}^{Grid} + BES_{t,oh,s}^{Grid}) \times rate\_exp_{t,oh,s} +$$
$$Gas_{t,oh,s}^{GB} \times rate\_gas] \times \frac{1}{kW^{kWh}} \tag{F.25}$$

F.1.2 Capacity charges optimization

In scenarios with capacity charges, the grid operator levies a demand charge on the maximum demand of electricity withdrawn within a 15 min time step. Such kw-based costs are charged on a monthly basis and on two different demand peaks of the user at two different rates: one for the highest peak that coincides with a critical load period in the grid (i.e., $max\_imp_{oh,s}^{on-peak}$) and one for the highest peak that does not coincide with a critical load period (i.e., $max\_imp_{oh,s}^{off-peak}$). Moreover, a minimum charge is levied for off-peak demand (i.e., $min\_kw^{off-peak}$), as this replaces fixed network charges. Given a 48-hour optimization horizon, optimized user's peaks in each *oh* are carried over to the following optimization (cf. Eq. F.26 and F.27). By doing this, the charges levied in previous optimizations are considered as sunk costs.

$$max\_imp_{oh,s}^{on-peak} \geq \begin{cases} 0, & \text{if } oh = 1 \\ max\_imp_{oh-1,s}^{on-peak}, & \text{otherwise} \end{cases} \tag{F.26}$$

$$max\_imp_{oh,s}^{off-peak} \geq \begin{cases} min\_kw^{off-peak}, & \text{if } oh = 1 \\ max\_imp_{oh-1,s}^{off-peak}, & \text{otherwise} \end{cases} \tag{F.27}$$

When a PV or BES is provided, an equivalent charge on a monthly is levied on the maximum feed-in coinciding with a critical injection period in the grid. Such on-peak injection charges are levied on the additional peak above the maximum annual import peak (cf. Section 3.2.2), which is why the optimization takes into account the demand peaks of the previous seasons (cf. Eq. F.28).

$$max\_exp_{oh,s}^{on-peak} \geq \begin{cases} 0, & \text{if } oh = 1 \text{ and if } s = 1 \\ max\_imp_{OH,s-1}^{on-peak}, & \text{if } oh = 1 \text{ and if } s > 1 \\ max\_exp_{oh-1,s}^{on-peak}, & \text{otherwise} \end{cases} \tag{F.28}$$

Such optimized user's peaks represent the caps on on-peak and off-peak imports (cf. Eq. F.29), as well as the cap on on-peak exports (cf. Eq. F.30).

$$imp_t^{cap} = \begin{cases} max\_imp_{oh,s}^{on-peak}, & \text{if } lpeak_t^{nw} = 1 \\ max\_imp_{oh,s}^{off-peak}, & \text{otherwise} \end{cases} \forall\ t \in oh, s \tag{F.29}$$

$$exp_t^{cap} = \begin{cases} max\_exp_{oh,s}^{on-peak}, & \text{if } epeak_t^{nw} = 1 \\ \infty, & \text{otherwise} \end{cases} \forall\ t \in oh, s \tag{F.30}$$

Therefore, in the scenario with demand charges, an additional constraint is set on imports from the grid (cf. Eq. F.31), whereas Eq. F.32 replaces the constraint defined in Eq. F.4.

$$Grid_t^{EEL} + Grid_t^{HP35} + Grid_t^{HP55} + Grid_t^{BES} \leq imp_t^{cap} \tag{F.31}$$

$$PV_t^{Grid} + BES_t^{Grid} \leq exp_t^{cap} \tag{F.32}$$

Finally, the kW-based costs resulting from capacity-based charges that are part of the objective function can be defined (cf. Eq. F.33). Given the 48-hour optimization horizon, the model would overestimate the weight of monthly capacity charges relative to the volumetric charges. Therefore, the capacity charges are adjusted in proportion to the share of the month in which they are calculated, namely $oh\_weight = \frac{2}{30}$.

$$\begin{aligned} kW\_wcosts_{oh,s} = (&max\_imp_{oh,s}^{on-peak} \times cc^{on-peak} + max\_imp_{oh,s}^{off-peak} \\ &\times cc^{off-peak} + max\_exp_{oh,s}^{on-peak} \times cc^{on-peak}) \times oh\_weight \end{aligned} \tag{F.33}$$

F.1.3 Objective function

The model minimizes the net costs within each 48-hour optimization horizon (cf. Eq. F.34). The optimization is implemented in Python using the Gekko Optimization Suite [79] and either the APOPT solver, in the case of a HES with a heat pump, or the IPOPT solver otherwise.

$$Obj = Min(kWh\_costs_{oh,s} + HP\_doc_{oh,s} + kW\_wcosts_{oh,s}) \tag{F.34}$$

Table 14: Parameters and variables of the operation module

Description	Symbol	Range/Bounds
Parameters:		
Exogenous electrical load (kW)	EEL_t	[0, 10.43]
Space heating load (kW)	SpH_t	[0, 3.86]
DHW load (kW)	DHW_t	[0, 12.08]
PV generation (kW)	PV_t^{gen}	[0, 0.745×PV_pow]
Constraint on PV feed-in (%)	$Feed-in^{limit}$	70
Constraint on grid pow. to HP (bool.)	$Grid_t^{HP\_on}$	{0,1}
Critical load period (bool.)	$lpeak_t^{nw}$	{0,1}
Critical injection period (bool.)	$epeak_t^{nw}$	{0,1}
Conversion rate KWh/kW	kW^{kWh}	4
Std. withdrawal rate (€/kWh)	$rate\_std_t$	cf. Table 3
HP withdrawal rate (€/kWh)	$rate\_hp_t$	cf. Table 3
Feed-in rate (€/kWh)	$rate\_exp_t$	cf. Table 3
Gas rate (€/kWh)	$rate\_gas$	cf. Table 3
On-peak capacity charge (€/kW)	$cc^{on-peak}$	cf. Table 3
Off-peak capacity charge (€/kW)	$cc^{off-peak}$	cf. Table 3
Derived parameters:		
Pow. from PV to EEL_t (kW)	PV_t^{EEL}	cf. Eq. F.1 and F.2
BES max input pow. (kW)	BES_ipow	$BES\_opow \div \eta^{cha} \div \eta^{dis}$
HP max input pow. at 35 °C (kW)	$HP35\_ipow_t$	$HP35\_opow_t \div COP35_t$
HP max input pow. at 55 °C (kW)	$HP55\_ipow_t$	$HP55\_opow_t \div COP55_t$
Heat from HS at 35 °C to SpH_t (kW)	$HS35_t^{SpH}$	SpH_t
Heat from HS at 55 °C to DHW_t (kW)	$HS55_t^{SpH}$	DHW_t
Heat from GB to SpH_t (kW)	GB_t^{SpH}	SpH_t
Variables:		
Pow. from PV to HP op. at 35 °C (kW)	PV_t^{HP35}	[0, $HP35\_ipow_t$]
Pow. from PV to HP op. at 55 °C (kW)	PV_t^{HP55}	[0, $HP55\_ipow_t$)]
Pow. from PV to BES (kW)	PV_t^{BES}	[0, BES_ipow_t]
Pow. PV to grid (kW)	PV_t^{Grid}	[0, PV_pow_t]
Pow. from grid to EEL_t (kW)	$Grid_t^{EEL}$	[0, +∞)
Pow. from grid to HP op. at 35 °C (kW)	$Grid_t^{HP35}$	[0, $HP35\_ipow_t$]
Pow. from grid to HP op. at 55 °C (kW)	$Grid_t^{HP55}$	[0, $HP55\_ipow_t$]
Pow. from grid to BES (kW)	$Grid_t^{BES}$	[0, BES_ipow_t]
Pow. from BES to EEL (kW)	BES_t^{EEL}	[0, BES_opow_t
Pow. from BES to HP op. at 35 °C (kW)	BES_t^{HP35}	[0, $HP35\_ipow_t$]
Pow. from BES to HP op. at 55 °C (kW)	BES_t^{HP55}	[0, $HP55\_ipow_t$]
Pow. from BES to grid (kW)	BES_t^{Grid}	[0, BES_opow_t]
BES SoC (kWh)	BES_soc_t	$[BES\_soc^{min}, BES\_soc^{max}]$
Heat from HP to HS35 (kW)	HP_t^{HS35}	[0, $HP35\_opow_t$]
Heat from HP to HS55 (kW)	HP_t^{HS55}	[0, $HP55\_opow_t$]
SoC of HS at 35 °C (kWh)	$HS35\_soc_t$	$[HS35\_soc^{min}, HS35\_cap]$
SoC of HS at 55 °C (kWh)	$HS35\_soc_t$	$[HS55\_soc^{min}, HS55\_cap]$
Max. coincident demand (kW)	$max\_imp_{oh,s}^{on-peak}$	cf. Eq. F.26
Max. non-coincident demand (kW)	$max\_imp_{oh,s}^{off-peak}$	cf. Eq. F.27
Max. coincident feed-in (kW)	$max\_exp_{oh,s}^{on-peak}$	cf. Eq. F.28
Intermediate variables:		
Cap on grid withdrawal (kW)	imp_t^{cap}	cf. Eq. F.29
Cap on grid feed-in (kW)	exp_t^{cap}	cf. Eq. F.30

Abbreviations: boolean (bool.), power (pow.), operating (op.)

F.2 Investment module

In this module, the model extends the optimized energy dispatch resulting from the operation module over an investment planning horizon (IPH) of 20 years. The EEL and the optimized heat pump load, as well as the energy dispatch of the gas heating system, remain constant over 20 years. The PV generation, in contrast, diminishes after each year of operation by a fixed rate (PV_deg, cf. Table 4). The energy dispatch of the PV electricity aims to replicate the optimized flows resulting from the operation module. After the first year, given the decrease in PV output, the model follows some priority rules: it matches firstly the flow to the EEL, secondly the flow to the HP load, thirdly the flow to the BES, and finally the export of power to the grid. However, in a scenario without demand charges, in the time steps in which the heat pump cannot be powered with grid electricity, the model matches firstly the flow from PV to the HP load, since whenever the optimized flows to the loads cannot be replicated because of insufficient PV electricity, the remaining demand is supplied by the grid. Conversely, in the case of insufficient generation, the power flows to the BES and the grid are simply curtailed. Moreover, the optimized dispatch of the first year cannot be fully replicated because of battery capacity fade. Since the capacity fade of the BES depends on its operation, the System Advisory Model (SAM, version 2021.12.2) [65] via its Python package PySAM (version 3.0.0) [68] is run to simulate battery aging over the 20-year IPH. In SAM, batteries are set on the basis of the BES characteristics,[63] which are assumed for the operation module. SAM default values for Li-NMC batteries with regard to the chemical and voltage properties are employed, as SAM simulates battery operation in a greater level of detail (e.g, AC-DC conversion efficiencies are not constant). With regard to the battery dispatch, the optimized dispatch resulting from the operation module is inputted as a target for SAM, which operates the battery accordingly, as long as this remains within the battery's operational limits. Moreover, load and generation profiles are inputted for a 365-day year, which is why the four 8-day typical periods are repeated 11 times plus one additional 8-day spring period and a period comprising the first 5 days of an autumn. With respect to the battery's capacity fade, the SAM lifetime model for Li-NMC batteries is employed. All HES components have a lifetime of 20 years. The battery bank, however, is replaced if the BES capacity reaches 80% of its initial value. In the case of a replacement, a liquidation value of the BES is calculated. This value depends on the residual capacity of the battery at the end of the investment planning horizon within the SAM's simulation (BES_rescap_Y).

$$repex\_liq = (1 - \frac{100 - BES\_rescap_Y}{100 - 80}) \times repex_Y \tag{F.35}$$

As a result of the modeling of PV and BES degradation, the energy dispatch for multiple consecutive 32-day periods (consisting of four 8-day typical periods) is obtained. One of these periods is selected (i.e, the 6^{th} iteration of 11) for each

[63] i.e., capacity, power rating, charge and discharge efficiencies.

year. Such a period is used as a basis for the conversion into annual cash flows. The volumetric charges (cf. Eq. F.36) and capacity charges (cf. Eq. F.37) are summed by each season and year. Note that not only power flows change from year to year due to system degradation, but energy rates (except FiTs) and capacity charges increase annually due to inflation.

$$\begin{aligned} kWh\_costs_{s,y} = \sum_{ts=1}^{TS} [& (Grid^{EEL}_{ts,s,y} + Grid^{BES}_{ts,s,y}) \times rate\_std_{ts,s,y} + \\ & (Grid^{HP35}_{ts,s,y} + Grid^{HP55}_{ts,s,y}) \times rate\_hp_{ts,s,y} \\ & -(PV^{Grid}_{ts,s,y} + BES^{Grid}_{ts,s,y}) \times rate\_exp_{ts,s,y} \\ & +Gas^{GB}_{ts,s,y} \times rate\_gas_y] \times \frac{1}{kW^{kWh}} \end{aligned} \tag{F.36}$$

$$\begin{aligned} kW\_costs_{s,y} = [& max\_imp^{on-peak}_{s,y} + (max\_exp^{on-peak}_{s,y} - max\_imp^{on-peak}_{y})] \times cc^{on-peak}_{y} \\ & +max\_imp^{off-peak}_{s,y} \times cc^{off-peak}_{y} \end{aligned} \tag{F.37}$$

In order to calculate the annual energy costs (cf. Eq. F.38), the 32-day period is scaled up to a full year, which is why a weight to each s is assigned. In the case of volumetric charges (vc_weight_s), such weights depend on the number of days of each season within a year: i.e., $\frac{90}{8}$ for winter, $\frac{92}{8}$ for spring and summer, $\frac{91}{8}$ for autumn. In the case of capacity charges (cc_weight_s), the weights correspond to the number of months of each season within a year, which are all equal to 3.

$$ene\_costs_y = \sum_{s=1}^{S} kWh\_costs_{s,y} \times vc\_weight_s + \sum_{s=1}^{S} kW\_costs_{s,y} \times cc\_weight_s \tag{F.38}$$

After adding up total[64] investment ($capex$), operating ($opex$) and replacement ($repex$) costs, the annual cash flows can be grouped in order to calculate the discounted cash flow (cf. Eq. F.39), for the case in which a small-business taxation regime is assumed (see [30] for details on fiscal aspects).

$$DCF^{SBT} = capex + \sum_{y=1}^{Y} \frac{opex_y}{(1+d)^y} + \sum_{y=1}^{Y} \frac{repex_y}{(1+d)^y} - \frac{repex\_liq}{(1+d)^Y} + \sum_{y=1}^{Y} \frac{ene\_costs_y}{(1+d)^y} \tag{F.39}$$

By adding the cash flow of VAT payments and reimbursements, either over the entire IPH (cf. Eq. F.40) or over the first 6 years(cf. Eq. F.41), either the discounted cash flow resulting from a regular taxation regime (DCF^{RT}) or from a mixed taxation regime (DCF^{MT}) can be obtained. Generally, the mixed

[64]Namely the sum of the costs of the different HES components (cf. Tables 4, 5 and 6).

taxation regime results in the lowest DCF,[65] which is why the results' section reports the financial assessment under this last taxation regime (cf. Section 5.1).

$$\begin{aligned} DCF^{RT} = capex &+ \sum_{y=1}^{Y} \frac{opex_y}{(1+d)^y} + \sum_{y=1}^{Y} \frac{repex_y}{(1+d)^y} - \frac{repex\_liq}{(1+d)^Y} \\ &+ \sum_{y=1}^{Y} \frac{ene\_costs_y}{(1+d)^y} + \sum_{y=1}^{Y} \frac{cf\_VAT_y}{(1+d)^y} \end{aligned} \tag{F.40}$$

$$\begin{aligned} DCF^{MT} = capex &+ \sum_{y=1}^{Y} \frac{opex_y}{(1+d)^y} + \sum_{y=1}^{Y} \frac{repex_y}{(1+d)^y} - \frac{repex\_liq}{(1+d)^Y} \\ &+ \sum_{y=1}^{Y} \frac{ene\_costs_y}{(1+d)^y} + \sum_{y=1}^{6} \frac{cf\_VAT_y}{(1+d)^y} \end{aligned} \tag{F.41}$$

By means of time-varying emission factors of grid electricity, $emf\_grid_{ts,s,y}$, declining at the annual rate $carbon\_emissions\_dec$ (cf. Section 3.4), as well as the constant emission factor of natural gas emf_gas, the net carbon emissions caused by the household energy demand and feed-in over the IPH are calculated (cf. Eq. F.42 and Eq. F.43). This represents the net impact on CO_2 emissions, which consist of (i) direct emissions from the GB; (ii) indirect emissions due to the withdrawal of grid electricity; as well as (iii) avoided emissions due to the feed-in of PV electricity into the grid.

$$\begin{aligned} carbon\_emissions_{s,y} = \sum_{ts=1}^{TS} [(&Grid^{EEL}_{ts,s,y} + Grid^{BES}_{ts,s,y} + Grid^{HP35}_{ts,s,y} + Grid^{HP55}_{ts,s,y}) \times emf\_grid_{ts,s,y} \\ &-(PV^{Grid}_{ts,s,y} + BES^{Grid}_{ts,s,y}) \times emf\_grid_{ts,s,y} \\ &+Gas^{GB}_{ts,s,y} \times emf\_gas] \times \frac{1}{kW^{kWh}} \end{aligned} \tag{F.42}$$

$$tot\_carbon\_emissions_y = \sum_{y=1}^{Y} \sum_{s=1}^{S} carbon\_emissions_{s,y} \times vc\_weight_s \tag{F.43}$$

[65] Because the mixed regime takes advantage of the benefits of the two other taxation variants. It starts under the regular taxation regime, meaning that the VAT levied on the initial investment costs of PV and BES is reimbursed. After 6 years, the prosumer can switch to the small-business taxation regime, meaning that self-consumed electricity can be exempted from VAT. In the case of HESs without PV and BES, the taxation regime plays no role, as the VAT levied on the heating systems cannot be reimbursed.

References

[1] H. Wirth, Aktuelle Fakten zur Photovoltaik in Deutschland, Daten und fakten, Fraunhofer ISE, Download von www.pv-fakten.de, Fassung vom 01.05.2022 (2022).

[2] J. Ossenbrink, How feed-in remuneration design shapes residential PV prosumer paradigms, Energy Policy 108 (June) (2017) 239–255. `doi:10.1016/j.enpol.2017.05.030`.

[3] J. Figgener, D. Haberschusz, K.-P. Kairies, O. Wessels, B. Tepe, D. U. Sauer, Wissenschaftliches Mess- und Evaluierungsprogramm Solarstromspeicher 2.0., Jahresbericht 2018, Institut für Stromrichtertechnik und Elektrische Antriebe - RWTH Aachen (2018).

[4] J. Figgener, C. Hecht, D. Haberschusz, J. Bors, K. G. Spreuer, K.-P. Kairies, P. Stenzel, D. U. Sauer, The development of battery storage systems in germany: A market review (status 2022), arXiv preprint arXiv:2203.06762`doi:https://doi.org/10.48550/arXiv.2203.06762`.

[5] J. Figgener, P. Stenzel, K. P. Kairies, J. Linßen, D. Haberschusz, O. Wessels, M. Robinius, D. Stolten, D. U. Sauer, The development of stationary battery storage systems in Germany – status 2020, Journal of Energy Storage 33. `doi:10.1016/j.est.2020.101982`.

[6] M. Frondel, N. Ritter, C. M. Schmidt, C. Vance, Economic impacts from the promotion of renewable energy technologies: The German experience, Energy Policy 38 (8) (2010) 4048–4056. `doi:10.1016/j.enpol.2010.03.029`.

[7] C. Jägemann, S. Hagspiel, D. Lindenberger, The economic inefficiency of grid parity: The case of German photovoltaics, EWI Working Paper No 13/19, Institute of Energy Economics at the University of Cologne (EWI) (2013).

[8] M. Frondel, C. M. Schmidt, C. Vance, Revisiting Germany's solar cell promotion: An unfolding disaster, Economic Analysis and Policy 44 (1) (2014) 3–13. `doi:10.1016/j.eap.2014.02.001`.

[9] M. Andor, M. Frondel, C. Vance, Installing Photovoltaics in Germany: A license to print money?, Economic Analysis and Policy 48 (2015) 106–116, energy. `doi:https://doi.org/10.1016/j.eap.2015.09.003`.

[10] M. Russo, V. Bertsch, A looming revolution: Implications of self-generation for the risk exposure of retailers, Energy Economics 92 (2020) 104970.

[11] BNetzA, Monitoring report 2020, Tech. rep., Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen (2021).

[12] W.-P. Schill, A. Zerrahn, F. Kunz, Prosumage of solar electricity: Pros, cons, and the system perspective, Economics of Energy and Environmental Policy 6 (1) (2017) 7–31. doi:10.5547/2160-5890.6.1.wsch.

[13] CEER, Position Paper on Renewable Energy Self-Generation, Ref.: C16-SDE-55-03, Council of European Energy Regulators (CEER) (2016).

[14] BNetzA, Monitoringbericht 2021, Tech. rep., Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen (2022).

[15] BMWi, EEG-Umlage 2022: Fakten und Hintergründe, Federal Ministry for Economic Affairs and Energy (2021).

[16] AGEB, Auswertungstabellen zur Energiebilanz Deutschland - Daten für die Jahre 1990 bis 2020, Tech. rep., ARBEITSGEMEINSCHAFT ENERGIEBILANZEN e.V. (2021).

[17] UBA, Emissionsübersichten in den Sektoren des Bundesklimaschutzgesetzes, Tech. rep., German Environment Agency (2021).

[18] UBA, Entwicklung der spezifischen Kohlendioxid- Emissionen des deutschen Strommix in den Jahren 1990 - 2020, Tech. Rep. CLIMATE CHANGE 45/2021, German Environment Agency (2021).

[19] Fraunhofer-ISE, Energy-charts, https://www.energy-charts.info, accessed: 2022-02-15 (2022).

[20] L. Ryan, S. L. Monaca, L. Mastrandrea, Designing retail tariffs to decarbonise the electricity system, in: 2017 14th International Conference on the European Energy Market (EEM), 2017, pp. 1–6. doi:10.1109/EEM.2017.7982022.

[21] A. Lahnaoui, P. Stenzel, J. Linssen, Techno-economic analysis of photovoltaic battery system configuration and location , Applied Energy 227 (September 2017) (2018) 497–505. doi:10.1016/j.apenergy.2017.09.093.

[22] G. Litjens, E. Worrell, W. van Sark, Influence of demand patterns on the optimal orientation of photovoltaic systems, Solar Energy 155 (2017) 1002–1014. doi:https://doi.org/10.1016/j.solener.2017.07.006.

[23] S. Quoilin, K. Kavvadias, A. Mercier, I. Pappone, A. Zucker, Quantifying self-consumption linked to solar home battery systems: Statistical analysis and economic assessment, Applied Energy 182 (2016) 58–67. doi:10.1016/j.apenergy.2016.08.077.

[24] V. Bertsch, J. Geldermann, T. Lühn, What drives the profitability of household PV investments, self-consumption and self-sufficiency?, Applied Energy 204 (2017) 1–15. doi:10.1016/j.apenergy.2017.06.055.

[25] J. Linssen, P. Stenzel, J. Fleer, Techno-economic analysis of photovoltaic battery systems and the influence of different consumer load profiles, Applied Energy 185 (2017) 2019–2025. doi:10.1016/j.apenergy.2015.11.088.

[26] S. Schopfer, V. Tiefenbeck, T. Staake, Economic assessment of photovoltaic battery systems based on household load profiles, Applied Energy 223 (2018) 229–248. doi:10.1016/j.apenergy.2018.03.185.

[27] S. La Monaca, L. Ryan, Solar PV where the sun doesn't shine: Estimating the economic impacts of support schemes for residential PV with detailed net demand profiling, Energy Policy 108 (2017) 731–741. doi:https://doi.org/10.1016/j.enpol.2017.05.052.
URL https://www.sciencedirect.com/science/article/pii/S0301421517303439

[28] J. López Prol, K. W. Steininger, Photovoltaic self-consumption regulation in Spain: Profitability analysis and alternative regulation schemes, Energy Policy 108 (2017) 742–754. doi:https://doi.org/10.1016/j.enpol.2017.06.019.
URL https://www.sciencedirect.com/science/article/pii/S0301421517303750

[29] A. Dietrich, C. Weber, What drives profitability of grid-connected residential PV storage systems? A closer look with focus on Germany, Energy Economics 74 (2018) 399–416. doi:10.1016/j.eneco.2018.06.014.

[30] G. Aniello, H. Shamon, W. Kuckshinrichs, Micro-economic assessment of residential PV and battery systems: The underrated role of financial and fiscal aspects, Applied Energy 281 (2021) 115667. doi:10.1016/j.apenergy.2020.115667.

[31] W. L. Schram, I. Lampropoulos, W. G. van Sark, Photovoltaic systems coupled with batteries that are optimally sized for household self-consumption: Assessment of peak shaving potential, Applied Energy 223 (2018) 69–81. doi:10.1016/j.apenergy.2018.04.023.

[32] G. Angenendt, S. Zurmühlen, H. Axelsen, D. U. Sauer, Comparison of different operation strategies for PV battery home storage systems including forecast-based operation strategies, Applied Energy 229 (May) (2018) 884–899. doi:10.1016/j.apenergy.2018.08.058.

[33] G. Litjens, E. Worrell, W. van Sark, Assessment of forecasting methods on performance of photovoltaic-battery systems, Applied Energy 221 (2018) 358–373. doi:https://doi.org/10.1016/j.apenergy.2018.03.154.

[34] T. Beck, H. Kondziella, G. Huard, T. Bruckner, Optimal operation, configuration and sizing of generation and storage technologies for residential heat

pump systems in the spotlight of self-consumption of photovoltaic electricity, Applied Energy 188 (2017) 604–619. doi:10.1016/J.APENERGY.2016.12.041.

[35] A. L. Klingler, The effect of electric vehicles and heat pumps on the market potential of PV + battery systems, Energy 161 (2018) 1064–1073. doi:10.1016/j.energy.2018.07.210.

[36] E. O'Shaughnessy, D. Cutler, K. Ardani, R. Margolis, Solar plus: A review of the end-user economics of solar PV integration with storage and load control in residential buildings, Applied Energy 228 (July) (2018) 2165–2175. doi:10.1016/j.apenergy.2018.07.048.

[37] D. Parra, M. K. Patel, Effect of tariffs on the performance and economic benefits of PV-coupled battery systems, Applied Energy 164 (2016) (2016) 175–187. doi:10.1016/j.apenergy.2015.11.037.

[38] T. Kaschub, P. Jochem, W. Fichtner, Solar energy storage in German households: profitability, load changes and flexibility, Energy Policy 98 (2016) 520–532. doi:10.1016/j.enpol.2016.09.017.

[39] H. Schwarz, H. Schermeyer, V. Bertsch, W. Fichtner, Self-consumption through power-to-heat and storage for enhanced PV integration in decentralised energy systems, Solar Energy 163 (January) (2018) 150–161. doi:10.1016/j.solener.2018.01.076.

[40] V. Heinisch, M. Odenberger, L. Göransson, F. Johnsson, Prosumers in the Electricity System—Household vs. System Optimization of the Operation of Residential Photovoltaic Battery Systems, Frontiers in Energy Research 6 (January). doi:10.3389/fenrg.2018.00145.

[41] M. C. Soini, D. Parra, M. K. Patel, Impact of prosumer battery operation on the cost of power supply, Journal of Energy Storage 29 (January) (2020) 101323. doi:10.1016/j.est.2020.101323.

[42] R. Green, I. Staffell, " Prosumage " and the British electricity market, Economics of Energy and Environmental Policy 6 (1) (2017) 33–50. doi:10.5547/2160-5890.6.1.rgre.

[43] K. Say, W. P. Schill, M. John, Degrees of displacement: The impact of household PV battery prosumage on utility generation and storage, Applied Energy 276 (March) (2020) 115466. arXiv:2003.06987, doi:10.1016/j.apenergy.2020.115466.

[44] M. Klein, A. Ziade, L. de Vries, Aligning prosumers with the electricity wholesale market – The impact of time-varying price signals and fixed network charges on solar self-consumption, Energy Policy 134 (2019) 110901. doi:https://doi.org/10.1016/j.enpol.2019.110901.

[45] D. Fett, D. Keles, T. Kaschub, W. Fichtner, Impacts of self - generation and self - consumption on German household electricity prices, Journal of Business Economics 89 (2019) 867–891. doi:10.1007/s11573-019-00936-3.

[46] M. Schwarz, J. Ossenbrink, C. Knoeri, V. H. Hoffmann, Addressing integration challenges of high shares of residential solar photovoltaics with battery storage and smart policy designs, Environmental Research Letters 14 (7) (2019) 74002. doi:10.1088/1748-9326/aaf934.

[47] A. J. Pimm, T. T. Cockerill, P. G. Taylor, Time-of-use and time-of-export tariffs for home batteries: Effects on low voltage distribution networks, Journal of Energy Storage 18 (June) (2018) 447–458. doi:10.1016/j.est.2018.06.008.

[48] S. Young, A. Bruce, I. MacGill, Potential impacts of residential PV and battery storage on Australia's electricity networks under different tariffs, Energy Policy 128 (2019) 616–627. doi:https://doi.org/10.1016/j.enpol.2019.01.005.

[49] C. Günther, W.-P. Schill, A. Zerrahn, Prosumage of solar electricity: Tariff design, capacity investments, and power sector effects, Energy Policy 152 (2021) 112168. doi:https://doi.org/10.1016/j.enpol.2021.112168.

[50] D. Fett, C. Fraunholz, D. Keles, Diffusion and system impact of residential battery storage under different regulatory settings, Energy Policy 158 (May) (2021) 112543. doi:10.1016/j.enpol.2021.112543.

[51] J. Thomsen, C. Weber, Getting Prices for Prosumers Right? Incentivizing Investment and Operation of Small-scale PV-Battery Storage Systems Through Prices, Charges and Levies, Zeitschrift für Energiewirtschaft (2021) 35–59doi:10.1007/s12398-020-00295-5.

[52] I. J. Pérez-Arriaga, J. D. Jenkins, C. Batlle, A regulatory framework for an evolving electricity sector: Highlights of the MIT utility of the future study, Economics of Energy and Environmental Policy 6 (1) (2017) 71–92. doi:10.5547/2160-5890.6.1.iper.

[53] CEER, CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition, Ref.: C19-DS-55-04, Council of European Energy Regulators (CEER) (2020).

[54] Eurelectric, Network Tariffs, Position paper, Eurelectric (2016).

[55] Leopoldina, acatech, Akademienunion, Coupling the different energy sectors - options for the next phase of the energy transition, Position paper, German National Academy of Sciences Leopoldina, acatech – National Academy of Science and Engineering, Union of the German Academies of Sciences and Humanities (2018).

[56] A. Bloess, W. P. Schill, A. Zerrahn, Power-to-heat for renewable energy integration: A review of technologies, modeling approaches, and flexibility potentials, Applied Energy 212 (December 2017) (2018) 1611–1626. doi:10.1016/j.apenergy.2017.12.073.

[57] S. Pfenninger, I. Staffell, Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data, Energy 114 (2016) 1251–1265. doi:https://doi.org/10.1016/j.energy.2016.08.060.

[58] I. Staffell, S. Pfenninger, Using bias-corrected reanalysis to simulate current and future wind power output, Energy 114 (2016) 1224–1239. doi:https://doi.org/10.1016/j.energy.2016.08.068.

[59] S. Pfenninger, I. Staffell, Renewables.ninja, www.renewables.ninja., accessed: 2022-02-15 (2022).

[60] N. Pflugradt, LoadProfileGenerator (version 10.5.0), https://www.loadprofilegenerator.de/, accessed: 2022-03-01 (2021).

[61] R. Passey, N. Haghdadi, A. Bruce, I. MacGill, Designing more cost reflective electricity network tariffs with demand charges, Energy Policy 109 (2017) 642–649. doi:https://doi.org/10.1016/j.enpol.2017.07.045.

[62] Agora-Energiewende, Eine Neuordnung der Abgaben und Umlagen auf Strom, Wärme, Verkehr. Optionen für eine aufkommensneutrale CO2 - Bepreisung (2018).

[63] Netztransparenz, Netztransparenz.de - Informationsplattform der Übertragungsnetzbetreiber, www.netztransparenz.de (2021).

[64] J. Bergner, V. Quaschning, Sinnvolle Dimensionierung von Photovoltaikanlagen für Prosumer, Kurzstudie, Hochschule für Technik und Wirtschaft Berlin (HTW Berlin) (2019).

[65] N. Blair, N. DiOrio, J. Freeman, P. Gilman, S. Janzou, T. Neises, M. Wagner, System Advisor Model (SAM) general description (version 2017.9.5), Tech. Rep. NREL/TP-6A20-70414, National Renewable Energy Lab (NREL) (2018).

[66] ITG, BDEW-Heizkostenvergleich Altbau 2017 - Ein Vergleich der Gesamtkosten verschiedener Systeme zur Heizung und Warmwasserbereitung in Altbauten, Institut für Technischen Gebäudeausrüstung Dresden Forschung und Anwendung GmbH (2021).

[67] IEA, Carbon intensity of electricity generation in selected regions in the Sustainable Development Scenario, 2000-2040, IEA, Paris, https://www.iea.org/data-and-statistics/charts/carbon-intensity-of-electricity-generation-in-selected-regions-in-the-sustainable-devel accessed: 2022-03-18 (2022).

[68] NREL, PySAM, https://github.com/nrel/pysam.

[69] Energie-Experten, Stromspeicher-Förderung: Kredite und Zuschüsse 2022/ 2023 im Überblick, https://www.energie-experten.org/erneuerbare-energien/photovoltaik/stromspeicher/foerderung, accessed: 2022-05-11 (2022).

[70] KfW, Erneuerbare Energien – Standard, https://www.kfw.de/inlandsfoerderung/Unternehmen/Energie-Umwelt/F%c3%b6rderprodukte/Erneuerbare-Energien-Standard-(270)/, accessed: 2022-05-11 (2022).

[71] Statista, Wärmeerzeuger - Absatz in Deutschland nach Kategorie 2021 , https://de.statista.com/statistik/daten/studie/379029/umfrage/absatz-von-waermeerzeugern-in-deutschland-nach-kategorie/, accessed: 2022-07-01 (2022).

[72] Statista, Wohnungsneubau - Anteil der Beheizungssysteme in Deutschland bis 2021, https://de.statista.com/statistik/daten/studie/37957/umfrage/beheizungssysteme-in-neubauten-im-jahr-2008/, accessed: 2022-07-01 (2022).

[73] Verivox, Verivox.de, https://www.verivox.de/, accessed: 2021-05-25 (2021).

[74] ENTSO-E, ENTSO-E Transparency Platform, https://transparency.entsoe.eu, accessed: 2022-03-01 (2021).

[75] Nasdaq, ECX EUA Futures, Continuous Contract #1. Non-adjusted price based on spot-month continuous contract calculations. Raw data from ICE, https://data.nasdaq.com/data/CHRIS/ICE_C1, accessed: 2022-01-18 (2021).

[76] BNetzA, SMARD.de, Benutzerhandbuch, Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen (2021).

[77] European Commission, EU ETS Handbook (2015).

[78] B. Tranberg, O. Corradi, B. Lajoie, T. Gibon, I. Staffell, G. B. Andresen, Real-time carbon accounting method for the European electricity markets, Energy Strategy Reviews 26 (2019) 100367. doi:https://doi.org/10.1016/j.esr.2019.100367.

[79] L. Beal, D. Hill, R. Martin, J. Hedengren, GEKKO Optimization Suite, Processes 6 (8) (2018) 106. doi:10.3390/pr6080106.