What can PV self-supply do for system integration?

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Abstract

PV self-supply has been a key economic driver for increasing PV installations in Germany during the past years. The main economic advantage are the lower levelized costs of electricity from PV rooftop systems compared to grid electricity. Based on the European Renewable Energy Directive, self-supply systems benefit from wide exemptions from surcharges and network charges. PV self-supply systems are expected to require lower feed-in tariffs as well as to foster system integration by motivating households and industries to optimize consumption to match PV generation better in order to benefit from their own PV installations. We examine the effects of different shares of PV self-supply systems on electricity prices and the revenue situation of other market participants. We see small to moderate effects on electricity prices. While most other electricity generators are largely unaffected, peak units as well as battery storage systems face revenue reductions. Furthermore, we examine network charge exemptions and quantify effects on the network costs allocated to different consumer groups.

Keywords: PV self-supply, system integration, climate protection, cost allocation

1. Introduction

Today, PV self-supply systems form the largest part of current PV investments in Germany. Within the framework of the OwnPV-Outlook project, we aim to investigate and evaluate the development and integration of PV self-supply systems into the future energy system. We evaluate possible and probable designs of future frameworks for PV self-supply systems, considering economical, technical, behavioral and regulatory aspects. The aim is to narrow the wide range of potential developments by determining an energetically and economically efficient and thus sustainable integration of PV self-supply systems into the energy system. In particular, we target the evaluation regarding microeconomic, technical, and macroeconomic aspects. This paper investigates effects of different shares of PV self-supply in future scenarios while keeping total installed PV capacities constant. In this way, the effects of PV self-supply alone can be singled out.

2. Methods

A range of PV self-supply systems is modelled and integrated into the fundamental model SCOPE SD as described in (Böttger, Härtel 2021 and Härtel, Ghosh, 2020). Most investment decisions in SCOPE SD are made endogenously, based on minimal system cost subject to energy demand coverage and emission restrictions. In such a model setup, neither the investment decision for nor the dispatch of decentral self-supply systems by PV owners is captured since it only optimizes coverage of all demands at minimal total costs, neglecting the economic perspective of the individual owner of a PV self-supply system and not accounting for non-monetary motivations such as the wish to supply oneself or to contribute to climate protection measures. In order to evaluate the effects of PV self-supply systems on the total energy supply system, different shares of various PV self-supply systems are fixed exogenously instead and the rest of the system is optimized in order to see feedback effects.

After completion of the SCOPE SD model optimizations, resulting system costs are transferred into an evaluation of cost allocation in order to quantify redistribution effects.

The modelled PV self-supply systems include single-family as well as multi-family houses with and without electric vehicles. In the presence of electric vehicles, the charging time is assumed to be optimized for maximal share of own PV electricity, neglecting potential time-dependent grid electricity prices. For details on electric vehicle charging strategies, see von Bonin et al. (2022).

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2.1 The SCOPE SD model

The SCOPE SD model is a linear optimization model, taking into account the European energy supply. SCOPE SD is a loose acronym for "sector-coupled optimization model", run in the configuration "scenario development". It has a high temporal resolution of one hour, considers an entire consecutive year, and covers a broad range of technologies. An overview of the model is depicted in Fig. 1. The input data include investment as well as operation and maintenance costs, including fuel costs, technology potentials and restrictions, and technology-specific availability time series for a broad range of technological options, as well as comprehensive energy demand time series from different energy sectors. These data are combined into a linear optimization model with the objective to supply all demands at minimal costs, subject to emission targets or emission allowance prices. Demand flexibility is taken into account. It yields optimal investment decisions and dispatch time series of different technologies to cover the energy demands.

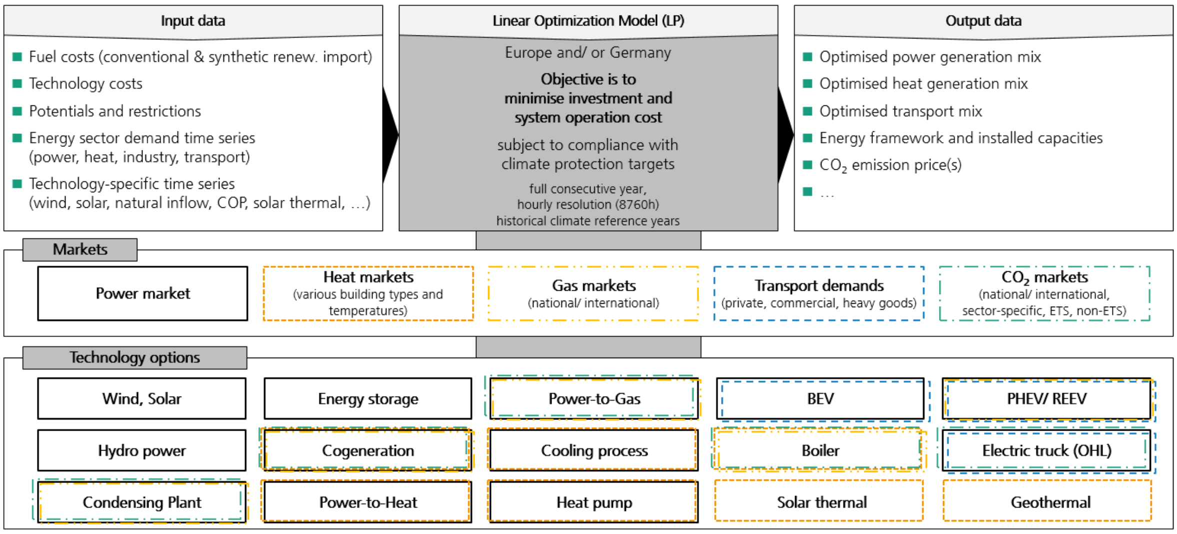

Fig. 1: Schematic overview of the SCOPE SD model components. Source: (Böttger, Härtel 2021).

Markets (energy demands and emission targets) are implemented as technology-coupling boundary conditions. For energy demands, that means that demand coverage is required with the option to use different technologies, such that the sum of all generation from different technologies meets the demands. For emissions, budget restrictions have to be observed and all emissions from different technologies are accounted for. Participation of a technology in a given market is indicated as a colored frame in Fig. 1.

2.2 Considered additional flexibility options

Additional flexibility options are considered only in the wholesale electricity market, not for system services. The extended usage of flexibility is incentivized by a reduction of electricity price components, which may be temporary and/or partial exemptions from all price components which are additional to procurement, trade, profit margin and emission allowances. These price components include taxes, charges and surcharges and are thus amenable to regulatory intervention. Modelled central technologies with additional flexibility potentials are electrolysis, synthetic methane production, central heat pumps (industrial or for district heating), direct electric heating, and central battery storage. To incentivize invest and operation of these flexible sector coupling technologies, they receive reductions in value-added tax, electricity tax and – if operated in a grid-friendly way – network charge exemptions. As usual, all central power plants participate in the electricity market and can thus also be considered as operating flexibly. The flexibility of wind and PV production of plants which receive a feed-in tariff is further increased by the option to shift remunerated generation to hours after the nominal end of their support scheme as opposed to producing as much as possible – even at negative prices – during their support period.

Decentral flexibility options modelled are charging of electric vehicles (EV), heat pump operation, PV self-supply systems with solar batteries, and air conditioning. Decentral technologies receive no exemptions from network charges, but investment and flexible operation are incentivized via electricity tax reductions and support for larger thermal storage capacities in heating and cooling technologies. Additionally, it is assumed that solar batteries can participate in the electricity market with charges and taxes only applied to storage losses.

2.3 Electricity demand, generation, and technological change

This paper considers the three scenario years 2030, 2040, and 2050. The assumed amounts of electricity generation from as well as consumption by different technologies are summarized in Fig. 2. The respective installed capacities for this base case scenario are depicted in Fig. 3, with details regarding total PV installations as well as PV self-supply systems in Fig. 4.

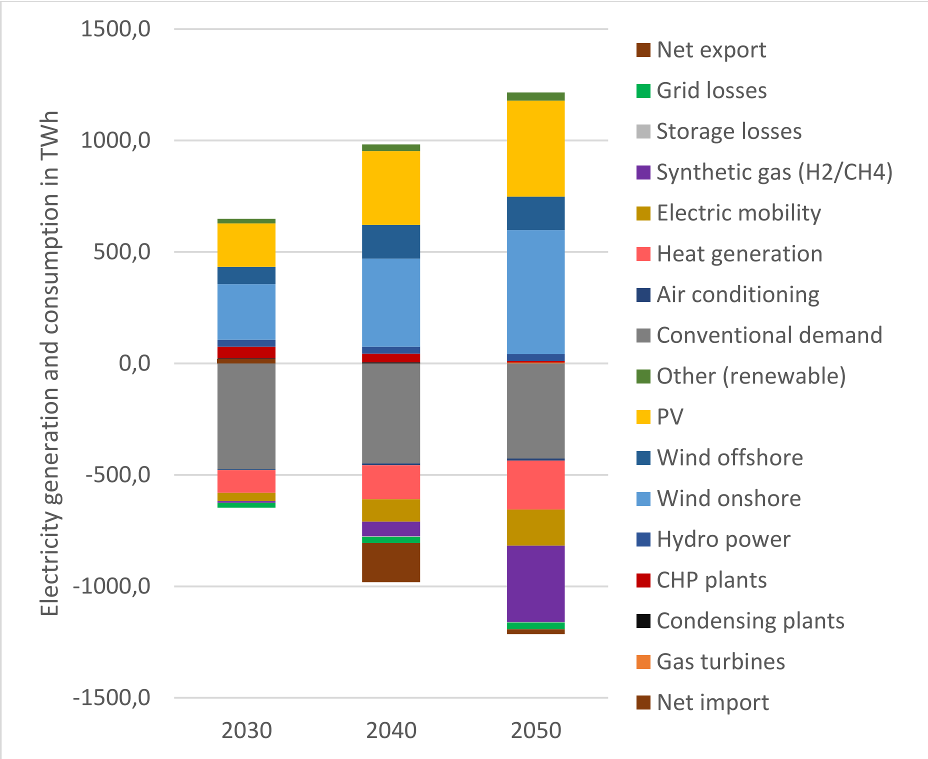

Fig. 2: Electricity generation and consumption for the three scenario years 2030, 2040, and 2050

Wind and PV installation increases are roughly in accordance with envisaged German government targets, with 205 GW total PV and 95 GW wind onshore capacity in 2030, rising to 450 GW PV and 200 GW Wind onshore in 2050. Wind offshore is installed up to "only" 40 GW. It is assumed that further offshore capacity is built – especially in later years –, but used exclusively for off-grid electrolysis. Another feature of the scenarios considered is the fast scale-up of synthetic gas production, yielding renewable hydrogen and methane.

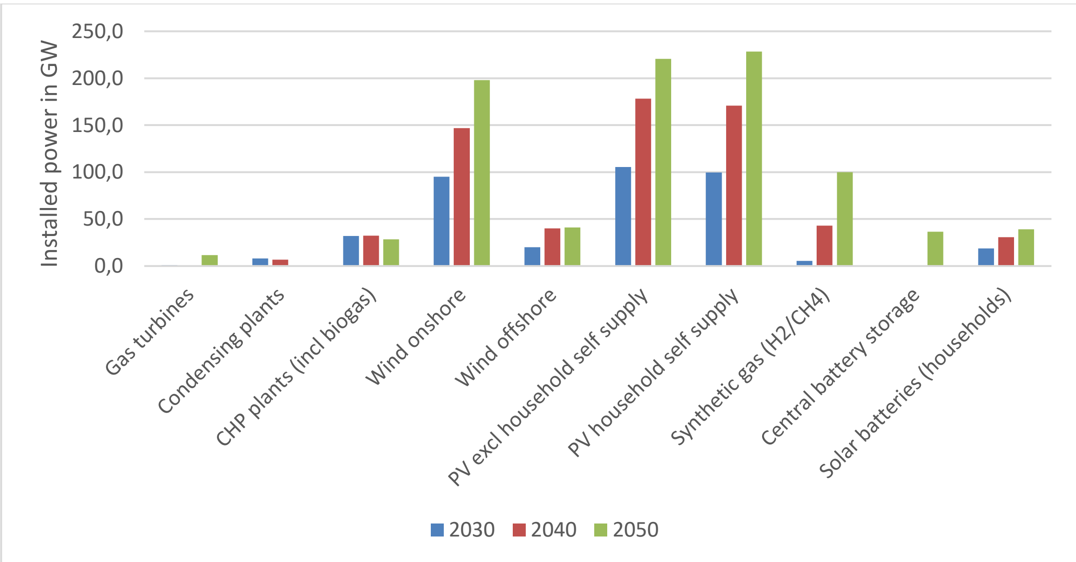

Fig. 3: Installed power capacities for the three scenario years 2030, 2040, and 2050

2.4 PV self-supply systems

In this work, PV self-supply systems for households usage are considered. Three different configurations are modelled: Single-family houses (SFH) with rooftop PV and solar batteries, SFH with rooftop PV, electric vehicles (EV) and solar batteries, and multi-family houses (MFH) with solar batteries and – on average – one EV per building. The solar batteries have a power capacity of 33% of the PV rooftop capacity for SFHs without EV, 20% for SFHs with EV, and 13% for MFHs with EV. The solar battery energy capacities range between 2.4 full load hours for MFH and 3.4 full load hours for SFH without EV (assuming charging/discharging with the batteries' full power capacity). EV charging strategies are described in detail in von Bonin et al. (2022). For the modelling under consideration in this paper, it is assumed that EVs are charged such that PV self-consumption is maximized. Further potential influences, such as spot-market dependent grid electricity prices or network load-dependent network charges are not taken into account.

In the base case scenario, it is assumed that these PV self-supply systems and other PV installations are roughly equal. As a sensitivity, the total installed PV capacity is kept constant, while the relative share of PV self-supply systems is varied between 75% and 125% of the base case scenario. These variants, together with the base case scenario, are illustrated in Fig. 4. The base case scenario is denoted as 100%, referring to a PV self-supply capacity of 100% of the base case. For the 75% scenario, PV self-supply is reduced to 75% of the 100% scenario, and for the 125% scenario, PV self-supply is increased to 125% of the 100% scenario, with changes in other PV installations compensating the change in total PV installations. It is apparent that for the 125% scenario in 2050, the PV self-supply capacity is in fact not increased to 125% of the base case. This is because the number of PV self-supply installations is capped by the number of respective buildings in Germany and it would be impossible to increase their number further. As a replacement, the non-self-supply PV installations are kept at their values of the base case scenario for this particular year.

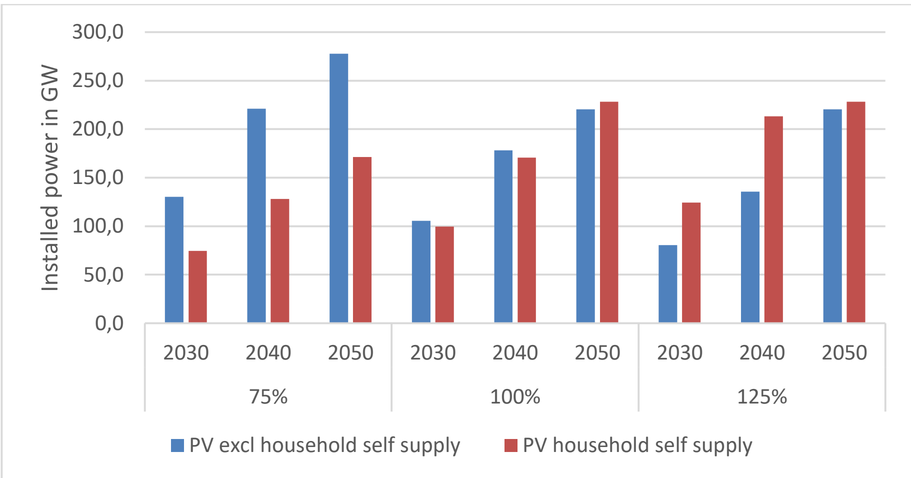

Fig. 4: Installed PV power capacities for the three scenario years 2030, 2040, and 2050, for the sensitivities of different shares of household PV self-supply

3. Results

3.1 Electricity prices and time series

Fig. 5 shows the average electricity prices and volatilities (standard deviations) for the base case 100% scenario as well as for the 75% and the 125% scenarios described in section 2.4.

There are no large deviations visible, but two trends can be observed:

- More PV self-supply → higher average wholesale market price
- More PV self-supply → lower volatility

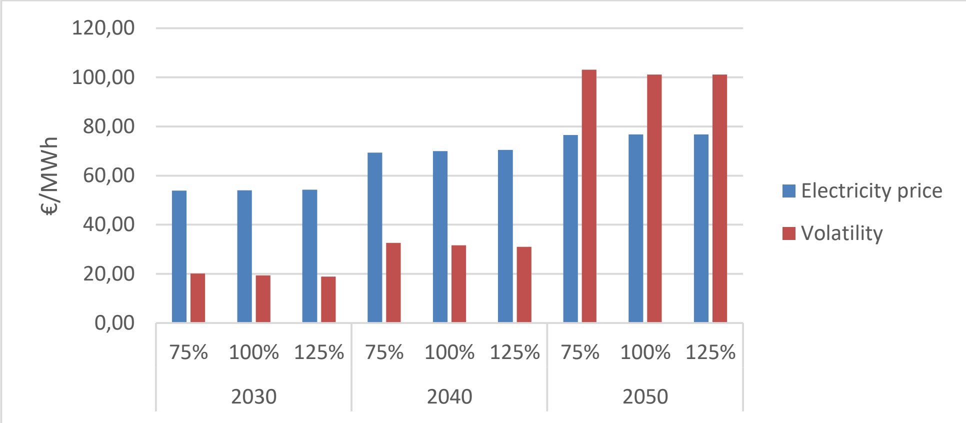

Fig. 5: Average electricity prices and price volatilities for the considered scenarios

Exemplary price time series for the base case 100% scenario for all three scenario years (2030, 2040 and 2050) for winter (January), the spring and fall transition periods (September), and summer (July) are shown in Fig. 6, Fig. 7, and Fig. 8, respectively.

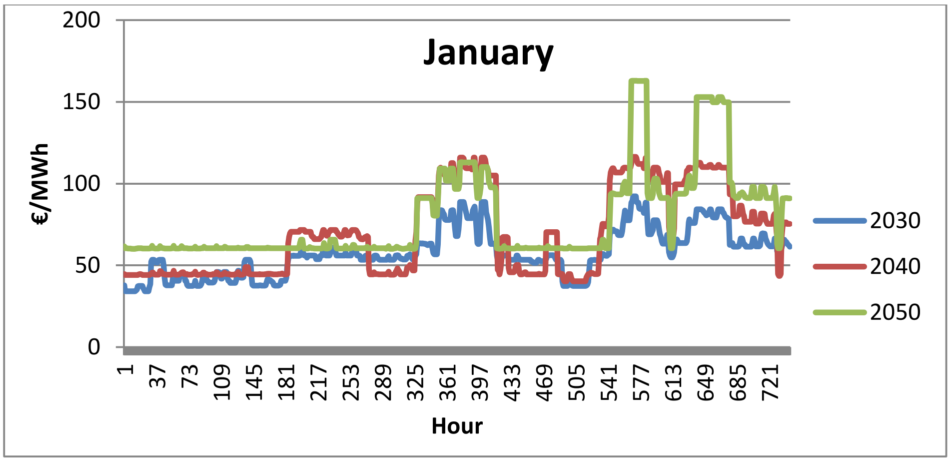

Fig. 6: Electricity prices for the different scenario years in January

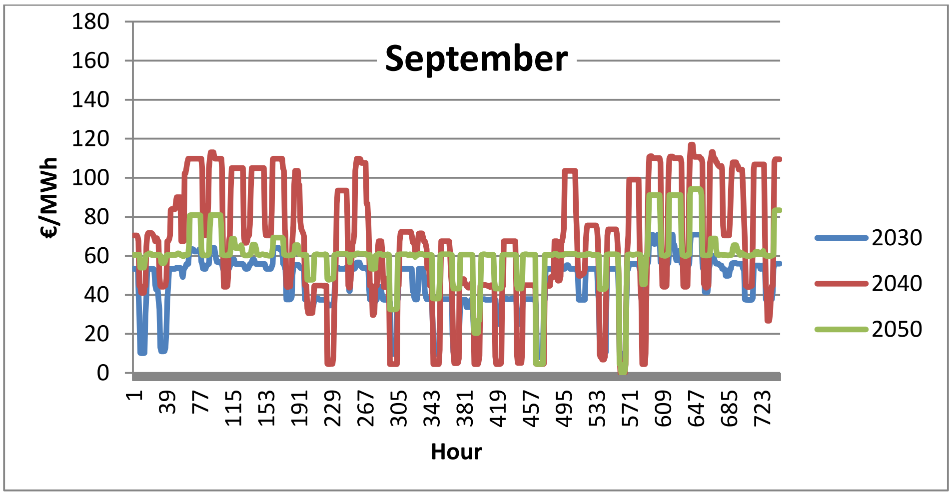

Fig. 7: Electricity prices for the different scenario years in September

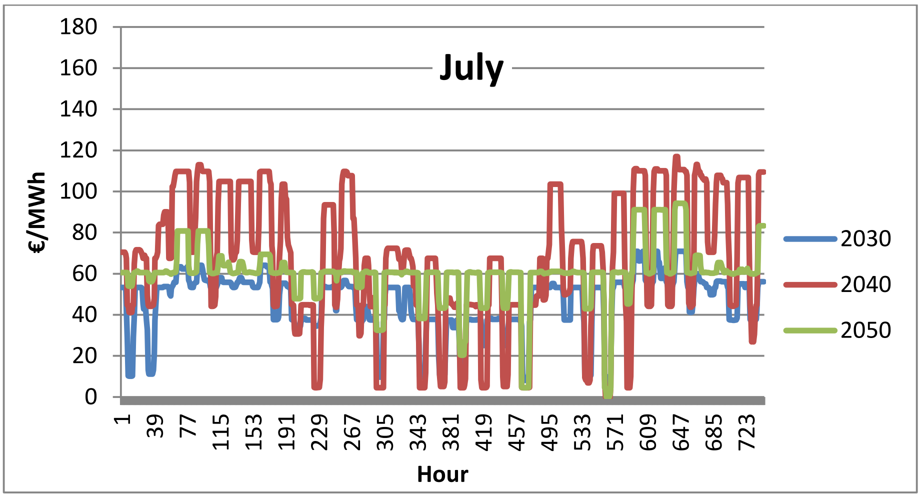

Fig. 8: Electricity prices for the different scenario years in July

Several general features can be observed in the price time series. First of all, the prices curves of different seasons show variations on different time scales. In winter, it is predominantly the scale of one to two weeks on which wind generation changes, which affects the electricity price. Transition periods and summer months are dominated by daily variations of PV production. When comparing the different scenario years, it is apparent that average prices and volatilities increase with time. Regarding the daily to weekly changes, the year 2040 plays a special role: Wind and PV generation has already been deployed to a large extent, whereas flexible consumption is lagging behind. This leads to particularly high amplitudes in daily price variations.

3.2 Revenue situation

What does a change in the PV self-supply share entail for the other participants of the electricity market? Fig. 9 shows the yearly average revenue from the wholesale electricity market for three selected technologies: The gas fired combined heat and power (CHP) plants, which serve heat generation as well as electricity generation, are not affected at all. Gas closed cycle (CCGT) plants likewise face very little change. Open-cycle gas turbines (OCGT), which operate only to serve rare peak demands, encounter larger changes. As a trend, their revenue decreases with increasing PV self-supply share. This is likely due to the added flexibility from solar batteries, making peak load plants less profitable.

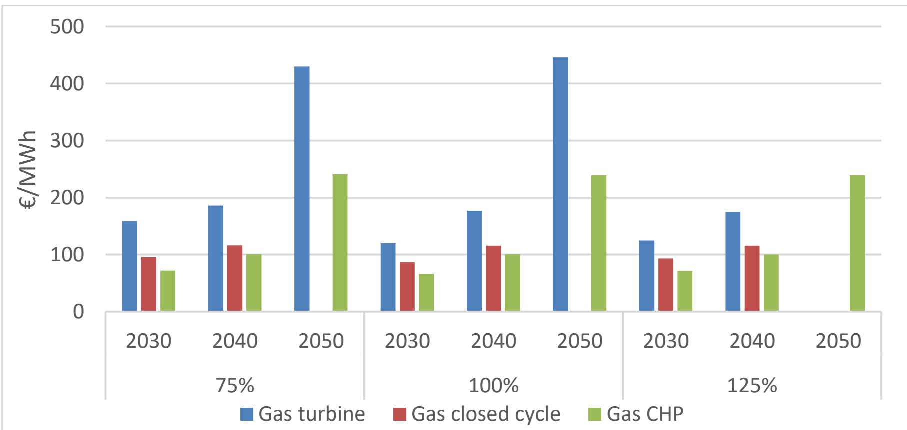

Fig. 9: Yearly average revenue of selected power plants

The revenue situation of the batteries, including the solar batteries, is shown in Fig. 10. Here, the trends are clearer: With solar batteries filling the niche of flexible storage, the average revenue per unit of stored energy goes down.

To sum up, the revenue situation of most electricity generation is largely unaffected by the share of PV self-supply systems in total installed PV capacity. For peak generators as well as batteries, the revenue decreases by small but noticeable amounts.

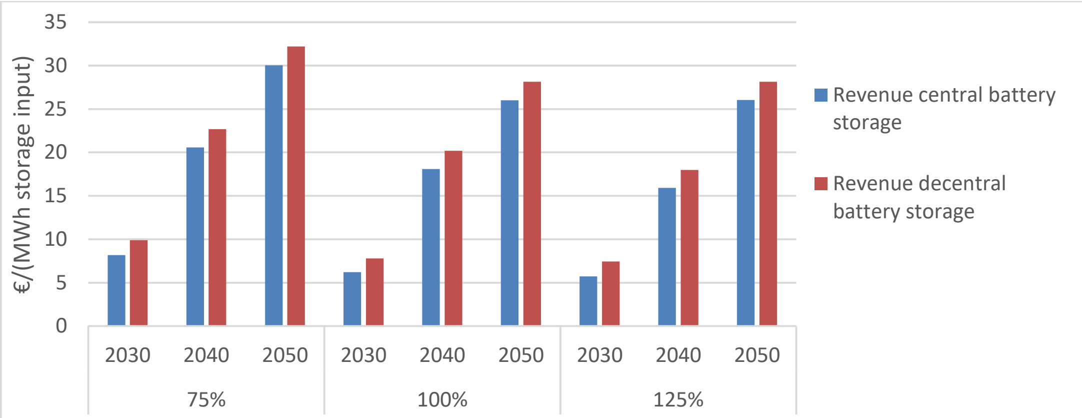

Fig. 10: Yearly average revenue of central and decentral battery storages. Due to storage losses, the input and output amount differ slightly. Here, € per MWh that is put into the storage is used

3.3 Allocation of network costs

As described in Section 2.2, the scenarios considered here come with extra amounts of flexibility, which are – among other measures – incentivized by network charge exemptions. In this section, the effects of these exemptions on other consumers are analyzed. To this end, two kinds of plots are used: The first compares total allocated network costs per consumer group, see Fig. 11 and Fig. 12. Network charge exemptions reallocate costs to non-privileged electricity consumers. In absolute terms, private households (household electricity, EV charging, heat pumps) make the largest contributions. The highest absolute network charge reductions are seen for energy intensive industries (mainly because they switch from fossil fuels to electric process heat) and synthetic hydrogen and methane production.

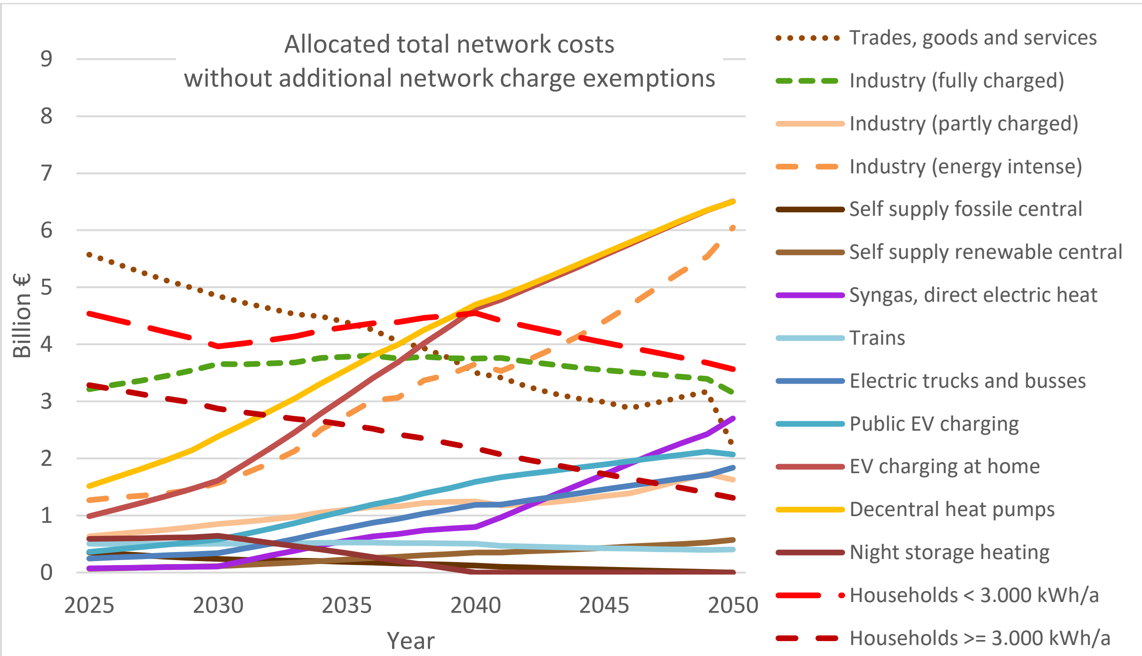

Fig. 11: Allocated total network costs without additional network charge exemptions, distributed across different types of consumption/consumer groups

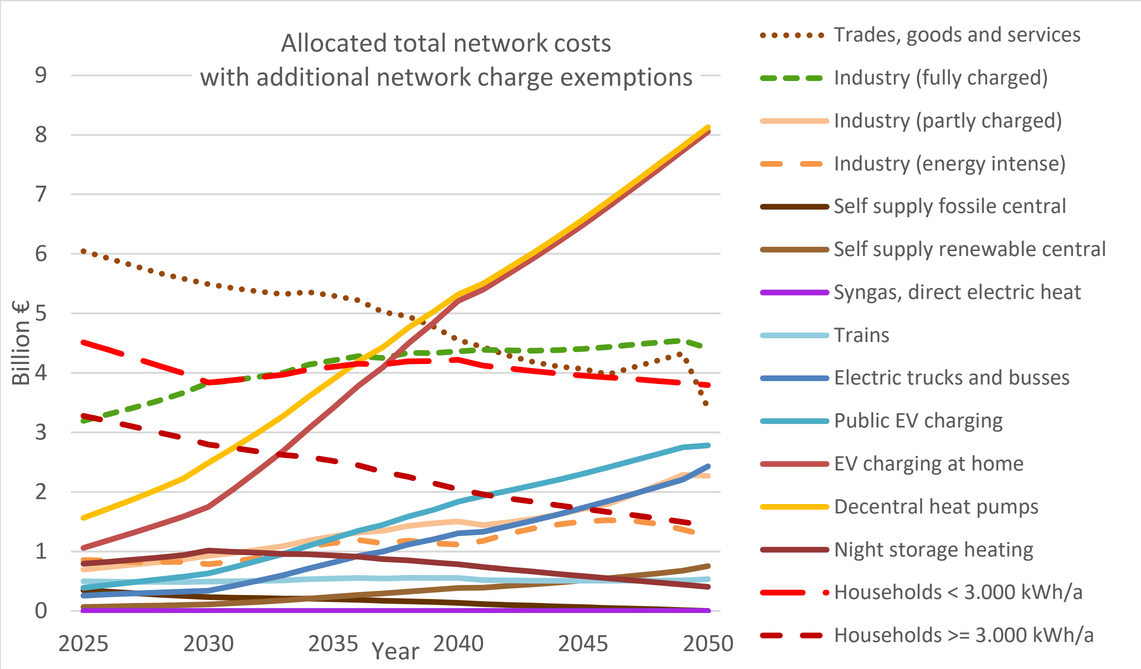

Fig. 12: Allocated total network costs with additional network charge exemptions, distributed across different types of consumption/consumer groups

Since the depiction of absolute costs does not take into account how much electricity is consumed by the various consumer groups, we use a second kind of plot, which shows the allocated grid costs relative to the total amount of energy consumed by the respective consumer groups. This is not to be confused with a volume-dependent network charge, as it includes all network costs allocated to a specific consumer group, regardless of how this contribution is made, which could be volume-specific tariffs, yearly payments, or peak load-dependent payments. According to our assumptions, the reduced network charge payments from exempt groups are uniformly distributed across all non-privileged consumers, such that the relative rise in network charges is the same for all non-privileged consumer groups.

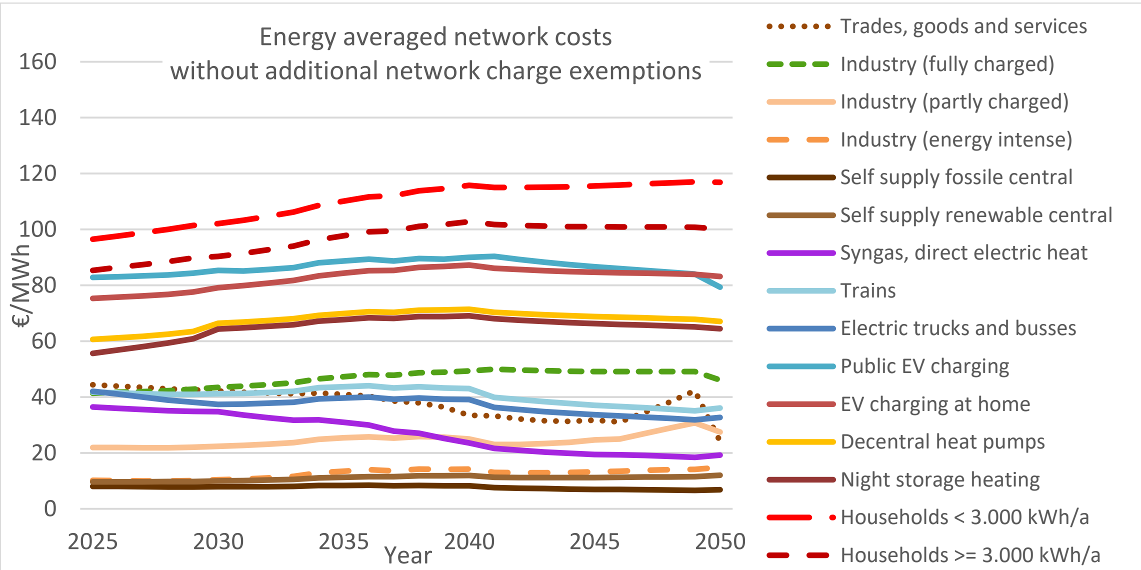

Fig. 13: Energy averaged network costs without additional network charge exemptions, distributed across different types of consumption/consumer groups

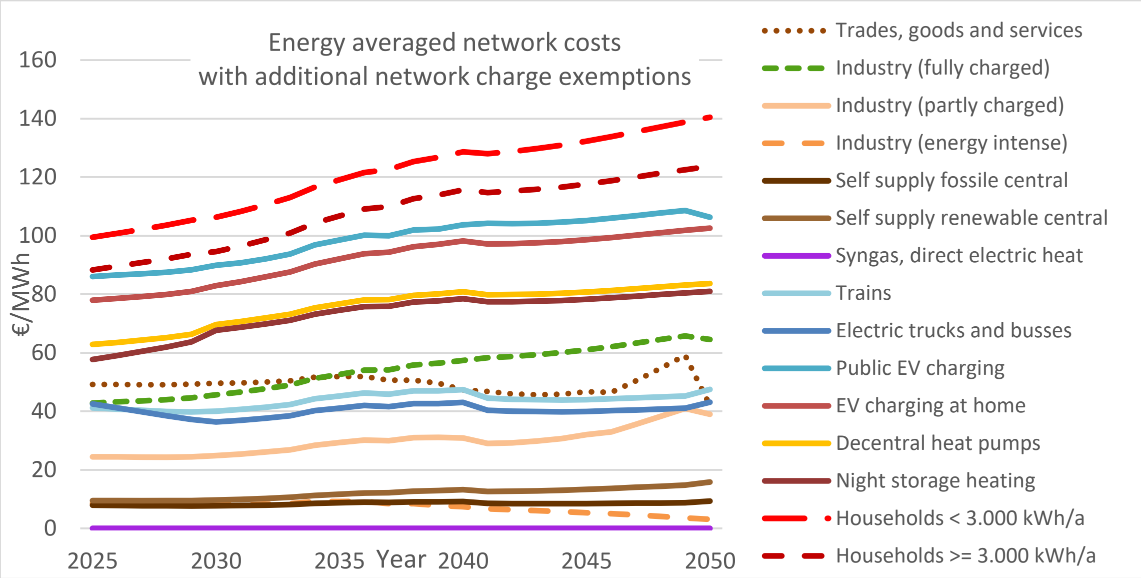

Fig. 14: Energy averaged network costs with additional network charge exemptions, distributed across different types of consumption/consumer groups

4. Conclusions and outlook

Electricity prices in wind and PV dominated power systems have seasonally different characteristics. In winter, weather fronts with a duration of one to two weeks determine wind generation, which in winter is the main source of power. Corresponding price fluctuations on this scale are clearly visible. In summer and to a smaller extent also in spring and fall, solar generation is prevalent and the daily PV generation pattern directly affects the electricity prices.

Electricity prices are relatively insensitive to different shares of PV self-supply systems among a constant amount of total installed PV electricity. As a tendency, the more PV self-supply systems there are, the less pronounced price extremes become. Average electricity prices tend to be marginally higher, and price volatility is slightly reduced. To sum up, PV self-supply systems have a tendency to improve PV system integration.

Higher shares of PV self-supply systems change the revenue situation of other market participants. For most market participants, the change is very slight, but for peak load units and battery storage, the change is more noticeable.

Network charge exemptions reallocate network costs to non-privileged electricity consumers. According to our assumptions, the reduced network charge payments from exempt groups are uniformly distributed across all non-privileged consumers, such that the relative rise in network charges is the same for all. In absolute terms, private households (household electricity, EV charging, heat pumps) make the largest contributions. The highest absolute network charge reductions are seen for energy intensive industries (who use power to heat applications) and synthetic gas production.

In this work, we restricted ourselves to the modelling of PV self-supply systems for the supply of private households. There are many more potential use cases, such as applications in industrial facilities or for trades, goods and services. In the latter two cases, the business cases are relatively straightforward, with one entity supplying itself. Additionally, more complex situations are conceivable, such as PV in combination with larger EV charging facilities or PV usage in city quarters for heat pumps, in order to supply several households with heat as well as electricity. These use cases will be addressed in future work.

5. Acknowledgments

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