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Interdependencies of prosumer households with the overall energy system with regard to system efficiency and distributional effects

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Interdependencies of prosumer households with the overall energy system with regard to system efficiency and distributional effects

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To Christine, Aaron and Jonah

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Abstract

The decarbonization of the global energy system to limit global warming on the basis of the Paris Agreement requires a massive expansion of renewable energy sources (RES). The technical implementation and technology mix of the energy transition will take place under technical, economic, socio-economic, and socio-ecological constraints. The latter two include the consideration of land use competition, environmental impact and social acceptance. Among other things, these restrictions make it difficult to implement large-scale projects in Germany, such as large on- or off-shore wind parks. Therefore, small-scale RES systems, especially rooftop photovoltaics (PV) on residential buildings, are emerging as an additional option for RES expansion. This is because these systems are not in direct competition with land, do not require any intervention in the local environment, and are widely accepted by society. In Germany, approximately 1.4 million small-scale PV systems (by 2021) below 10 $\mathrm{kW_p}$ have been installed in the past 20 years, supported by the Renewable Energy Sources Act (EEG). Together with these installations, a new group of market players has emerged, namely prosumers, who simultaneously *pro*-duce and con-*sume* energy (electricity). In recent years, newly installed PV systems are predominantly installed in combination with battery storage systems. The share of electric cars in the mobility sector and electric heat pumps in the heating sector has increased continuously and in parallel. These distributed generation and storage options enable prosumers to play an active role in the energy system. However, prosumers' actual behavior is largely determined by the regulatory framework. In Germany, for example, prosumers in the household sector are generally not direct participants in the wholesale market, but rather in the retail market with retail electricity prices that include regulatory price components such as network usage fees. As a result, for roughly the past decade, an (indirect) incentive has been created by constantly rising electricity prices and simultaneously falling feed-in tariffs to consume the maximum amount of self-generated electricity in order to avoid expensive external electricity purchases. In more abstract terms, the regulatory framework thus influences prosumers' investment and operating behavior. Prosumers already represent an important source of private RES investment today. However, the current regulatory framework does not provide targeted incentives to ensure that systems installed through prosumer investments are integrated into the overall system in a way that serves the system. This has implications for various levels (scales) of the energy system, as illustrated by the following:

First, at the household level, distribution effects occur at the expense of traditional consumer households without PV. This is because these households must currently compensate for the network charges that prosumers avoid through self-consumption to refinance the grid infrastructure and operating costs. Second, at the level of the local distribution grid, prosumers can impose thermal stress on local network structures, for example, through feed-back peaks from excess PV, which are additionally amplified by simultaneity effects. Third, at the wholesale level, a large number of prosumers can lead to additional system costs if the operational behavior of distributed storage negatively affects the operation of central power plants and leads to additional fuel and CO_2 costs.

A deeper – and quantitative – understanding of these interactions between prosumers and the power system is the goal of this cumulative thesis. The question of what the impacts are at different scales of the energy system is thus answered through analyses of three scientific publications in an overall context.

The focus of the first publication (in *Energy Policy*) is on household-level impacts. Based on empirical data from more than 1.4 million small-scale PV systems and using statistical measures, the study examines the socioeconomic impact of the EEG over the past 20 years. In a first step, the technical potential for rooftop PV systems is quantified with regional resolution and compared with actual utilization. The results reveal that the utilization of the technical potential differs significantly from region to region. This is accompanied by significant regional differences in the distribution of household costs for electricity. For prosumer households, both the regulatory profits (EEG remuneration) and avoided electricity purchase costs through self-consumption are considered, as well as the corresponding investment costs for the PV and storage systems. It can be seen that some counties, especially in the south of Germany, have significantly lower net electricity costs on average, while the majority of counties are net burdened by the EEG. Aggregated over the whole of Germany, the EEG thus leads to a cost shift of more than half a billion euros to the detriment of traditional consumer households. The maximization of self-consumption today (2021) accounts for approximately half of the total effect. Translated to the household level, this means that prosumers have 40 % lower net costs for their annual electricity than consumers on average in Germany.

The effects of prosumer behavior in response to the regulatory framework are explored in the second publication (in *IEEE Transactions on Power Systems*). Here, on the one hand, a methodological abstraction is made to general regulatory frameworks for levy-based RES support schemes and volumetric network charge designs, and, on the other hand, the analysis is extended to consider system effects and impacts on the overall system (wholesale market). Using a linear optimization model of the German electricity market and extensive parameter variations, the effects of prosumer decisions regarding investment in and operation of PV systems and battery storages are considered. The focus is on a realistic representation of strategic prosumer behavior via corresponding restrictions in the system modeling. In addition, the analysis considers heat applications (electric heat pumps and thermal storage), which represent further decentralized flexibility options in a sector-integrated energy system. It is shown that the actual operation mode of the distributed generation and storage units has a significant influence on the overall system costs. Thus, for future systems with high RES as well as prosumer shares, the total costs for systems comparable to the German electricity market could increase by more than EUR 1 billion if the corresponding decentralized flexibilities are either not integrated or incompletely integrated into the overall market. At the same time, this publication addresses further possible impacts of prosumer behavior at the distribution grid level by analyzing the maximum feed-in peaks as a function of different storage operation strategies. This analysis also provides the link to the third publication.

In the third journal paper (in *Energies*), the effects of prosumer behavior are investigated with a special focus on simultaneity effects at the local grid level. Different operating strategies for distributed PV and battery storage systems are considered, derived from different regulatory frameworks. To this end, this work couples different control algorithms of distributed systems (a) with an investigation of simultaneity effects at the local network node level and (b) with a linear optimization model of the electricity market. In addition to the previous analyses, which focus on the existing regulatory framework in its current form, this work also investigates a further development toward a new network charge design. In contrast to the existing regulatory framework, this new network charge design is based on the network capacity utilization considering simultaneity effects. It is shown that such a capacitive network charge mechanism can indeed lead to network-relieving behavior. At the same time, a fairer distribution of the refinancing costs of network infrastructure and operation can be achieved compared with volumetric network charges. Since network charges are a significant component of the retail electricity price, this would allow for better alignment of the overall burden of supplying electricity to prosumer and consumer households. A key added value of this work is the simultaneous consideration of all three scales of the energy system: individual (household), local (grid), and global (system). The study thereby demonstrates the complexity of the interactions between these system levels. While capacitive network charges are positive in terms of both socioeconomic impact and physical network relief, system-level impacts might be less beneficial. Viewed another way: controlling distributed flexibilities according to the market price signal would lead to a more effective integration of the overall available RES capacities and thus to both lower system costs and lower CO_2 emissions – but at the cost of a comparatively higher local network capacity utilization. The additional consideration of widespread electric mobility in the future does not fundamentally change this picture – which, at the same time, provides an important indication of the stability of the results with respect to parametric uncertainties.

Kurzfassung

Die Dekarbonisierung des globalen Energiesystems zur Begrenzung der Erderwärmung auf Basis des Klimaschutzabkommens von Paris erfordert einen massiven Ausbau Erneuerbarer Energien (EE). Die technische Umsetzung und der Technologiemix der Energiewende erfolgt entlang technischer, wirtschaftlicher, sozioökonomischer und sozioökologischer Rahmenbedingungen. Die beiden letzteren schließen etwa die Berücksichtigung von Flächenkonkurrenzen, Umweltauswirkungen und gesellschaftlicher Akzeptanz ein. Unter anderem aufgrund dieser Restriktionen ist gerade in Deutschland eine Umsetzung von Großprojekten – beispielsweise große Windparks and Land oder auf See – erschwert. Umso mehr rücken daher EE-Kleinanlagen, insbesondere Aufdach-Photovoltaik (PV) auf Wohngebäuden, als zusätzliche Möglichkeit des EE-Ausbaus in den Fokus. Denn diese Anlagen stehen nicht in direkter Flächenkonkurrenz, bedürfen keiner Eingriffe in die lokale Umwelt und sind gesellschaftlich breit akzeptiert. In Deutschland sind in den vergangenen 20 Jahren, gefördert durch das Erneuerbare-Energien-Gesetz (EEG), etwa 1,4 Millionen PV-Kleinanlagen (bis 2021) unter 10 $\mathrm{kW_p}$ installiert worden. Gemeinsam mit diesen Anlagen ist eine neue Akteursgruppe an Markteilnehmern entstanden, die sogenannten Prosumenten, die zugleich Energie (Strom) *pro*-duzieren und kon-*sumieren*. Neuinstallierte PV-Anlagen werden in den letzten Jahren überwiegend in Kombination mit Batteriespeichern verbaut. Gleichzeitig ist auch der Anteil von Elektroautos im Bereich Mobilität und elektrischer Wärmepumpen im Bereich Wärme in den letzten Jahren kontinuierlich gestiegen. Diese dezentralen Erzeugungs- und Speicheroptionen ermöglichen Prosumenten, eine aktive Rolle im Energiesystem einzunehmen. Dabei wird das tatsächliche Verhalten von Prosumenten maßgeblich durch den regulatorischen Rahmen bestimmt. In Deutschalnd etwa sind Prosumenten im Haushaltsbereich in der Regel nicht direkte Teilnehmer am Großhandel, sondern im Endkundenmarkt mit Endkundenstrompreisen, die regulatorische Preiskomponenten wie Netznutzungsentgelte enthalten. Dies führt dazu, dass seit etwa 10 Jahren ein (indirekter) Anreiz erzeugt wird durch stetig steigende Strompreise bei gleichzeitig sinkender Einspeisevergütung, den erzeugten Strom maximal selbst zu verbrauchen, um teuren, externen Strombezug zu vermeiden. Abstrakter formuliert beeinflusst demnach der regulatorische Rahmen sowohl das Investitions- als auch das Betriebsverhalten von Prosumenten. Prosumenten stellen heute schon eine wichtige Quelle für private EE-Investitionen dar. Allerdings werden im derzeitigen regulatorischen Rahmen keine zielgerichteten Anreize gesetzt, dass die durch Prosumenten-Investitionen installierten Anlagen systemdienlich in das Gesamtsystem integriert werden. Dies hat Auswirkungen auf verschiedenen Größenskalen im Energiesystem, wie folgende Aspekte beispielhaft illustrieren:

Erstens: Auf Ebene der Haushalte resultieren Verteileffekte zu Lasten der klassischen

Konsumenten-Haushalte ohne PV. Denn diese müssen derzeit etwa bei der Refinanzierung der Netzinfrastruktur und Betriebskosten die durch Eigenverbrauch vermiedenen Netzentgelte von Prosumenten übernehmen. Zweitens: Auf Ebene des lokalen Verteilnetz können Prosumenten etwa durch Rückspeise-Spitzen von Überschuss-PV, welche durch Gleichzeitigkeitseffekte zusätzlich verstärkt werden, lokale Netzstrukturen thermisch belasten. Drittens: Auf Großhandelsebene kann eine große Anzahl von Prosumenten zu zusätzlichen Systemkosten führen, wenn sich das Betriebsverhalten der dezentralen Speicher negativ auf die Betriebsweise zentraler Kraftwerke auswirkt und zu zusätzlichen Brennstoff- und CO_2-Kosten führt.

Ein tieferes – und auch quantitatives – Verständnis dieser Wechselwirkungen zwischen Prosumenten und dem Energiesystem ist das Ziel der vorliegenden kumulativen Dissertation. Die Fragestellung nach den Auswirkungen auf unterschiedlichen Größenskalen wird dabei durch die Analysen dreier wissenschaftlicher Veröffentlichungen im Gesamtzusammenhang beantwortet.

Der Fokus der ersten Veröffentlichung (in *Energy Policy*) liegt auf den Auswirkungen auf Haushaltsebene. Die Studie untersucht auf Basis empirischer Daten von über 1,4 Millionen PV-Kleinanlagen und unter Verwendung statistischer Maße die sozioökonomischen Auswirkungen des EEG der vergangenen 20 Jahre. In einem ersten Schritt wird das technische Potenzial für Aufdach-PV-Anlagen regional aufgelöst quantifiziert und mit der tatsächlichen Ausnutzung verglichen. Dabei zeigt sich, dass das technische Potenzial regional bisher deutlich unterschiedlich ausgenutzt wird. Damit einher gehen signifikante regionale Unterschiede bei der Verteilung der Haushaltskosten für Strom. Dabei werden für Prosumenten-Haushalte sowohl die regulatorischen Profite (EEG-Vergütung) und vermiedene Strombezugskosten durch Eigenverbrauch berücksichtigt, als auch die entsprechenden Investitionskosten für die PV- und Speichersysteme. Es zeigt sich, dass einige Landkreise insbesondere im Süden Deutschlands im Durchschnitt deutlich niedrigere Netto-Stromkosten aufweisen, während die Mehrzahl der Landkreise netto belastet wird durch das EEG. Über ganz Deutschland aggregiert führt das EEG auf diese Weise zu einer Kostenverschiebung von über einer halbe Milliarde Euro zu Lasten von klassischen Konsumenten-Haushalten. Dabei trägt die Maximierung von Eigenverbrauch heute (2021) circa zur Hälfte des Gesamteffektes bei. Übersetzt auf Haushaltsebene bedeutet dies, dass Prosumenten im Durchschnitt über Deutschland netto 40 Prozent geringere Kosten für den jährlichen Strombedarf aufweisen als Konsumenten.

Die Auswirkungen von Prosumenten-Verhalten als Reaktion auf den regulatorischen Rahmen werden in der zweiten Veröffentlichung (in *IEEE Transactions on Power Systems*) aufgegriffen. Dabei wird einerseits methodisch eine Abstrahierung vorgenommen auf allgemeine regulatorische Rahmensetzungen zur umlagefinanzierten EE-Förderung und volumetrische Netzentgeltmechanismen, andererseits wird die Analyse erweitert um die Betrachtung von Systemeffekten und Auswirkungen auf das Gesamtsystem (Großhandel). Unter Verwendung eines linearen Optimierungsmodells des deutschen Elektrizitätsmarktes sowie umfangreicher Parameter-Variationen werden die Auswkirkungen von Prosumenten-Entscheidungen hinsichtlich Investition in und Betrieb von PV-Anlagen und Speichern berücksichtigt. Dabei liegt der Fokus auf einer realistischen Abbildung des strategischen Prosumenten-Verhaltens über entsprechende Restriktionsbedingungen in der Systemmodellierung. Zudem berücksichtigt die Analyse auch Wärmeanwendungen (elektrische Wärmepumpen und thermische Speicher), die weitere dezentrale Flexibilitätsoptionen in einem sektorintegrierten Energiesystem darstellen. Es zeigt sich, dass insbesondere die tatsächliche Betriebsweise der dezentralen Erzeugungs- und Speichereinheiten maßgeblichen Einfluss auf die Gesamtsystemkosten hat. So könnten für zukünftige Systeme mit hohen EE- als auch Prosumenten-Anteilen die Gesamtkosten für Systeme vergleichbar mit Deutschland um mehr als 1 Milliarde Euro steigen, wenn die entsprechenden dezentralen Flexibilitäten nicht oder nur unvollständig in den Gesamtmarkt integriert werden. Gleichzeitig reißt diese Veröffentlichung weitere mögliche Auswirkungen von Prosumenten-Verhalten auf Verteilnetzebene an, indem die maximalen Rückspeisespitzen als Funktion unterschiedlicher Speicherbetriebsstrategien analysiert werden. Dies stellt zugleich die Verbindung zur dritten Veröffentlichung dar.

In dieser dritten Arbeit (in *Energies*) werden die Auswirkungen von Prosumenten-Verhalten mit besonderem Fokus auf Gleichzeitigkeitseffekte auf lokaler Netzebene untersucht. Es werden verschiedene Betriebsstrategien für dezentrale PV- und Batteriespeichersysteme betrachtet, die sich aus unterschiedlichen regulatorischen Rahmensetzungen ableiten. Dafür werden in dieser Arbeit unterschiedliche dezentrale Steuerungsalgorithmen gekoppelt a) mit einer Untersuchung von Gleichzeitigkeitseffekten auf lokaler Netzknotenebene und b) mit einem linearen Optimierungsmodells des Elektrizitätsmarktes. Zusätzlich zu den bisherigen Analysen, die sich auf den bestehenden regulatorischen Rahmen in seiner derzeitigen Form fokussieren, wird in dieser Arbeit auch eine Weiterentwicklung in Richtung eines neuen Netzentgelt-Designs untersucht. Dieses basiert, anders als bisher, auf der kapazitiven Netzauslastung unter Berücksichtigung von Gleichzeitigkeiten. Es zeigt sich, dass ein solcher kapazitiver Netzentgeltmechamismus in der Tat zu einem netzentlastenden Verhalten führen kann. Gleichzeitig kann auch eine im Vergleich zu volumetrischen Netznutzungsentgelten fairere Verteilung der Refinanzierungskosten von Netzinfrastruktur und -betrieb erzielt werden. Da die Netznutzungsentgelte einen wesentlichen Bestandteil des Endkundenstrompreises darstellen, könnten auf diese Weise insgesamt die Belastungen für die Stromversorgung von Prosumenten- und Konsumenten-Haushalten angeglichen werden. Ein wesentlicher Mehrwert dieser Arbeit ist die gleichzeitige Betrachtung aller drei Größenskalen: Individuell (Haushalt), lokal (Netz) und global (System). Dabei demonstriert die Studie die Komplexität der Wechselwirkun-

gen zwischen diesen Systemebenen. Während kapazitive Netznutzungsentgelte sowohl positiv hinsichtlich sozio-ökonomischer Verteilwirkung als auch physikalischer Netzentlastung zu bewerten sind, sind die Auswirkungen auf Systemebene weniger vorteilhaft. Anders herum betrachtet: Eine Steuerung der dezentralen Flexibilitäten entsprechend des Marktpreissignals würde zu einer effektiveren Integration der insgesamt vorhandenen EE-Kapazitäten führen und damit sowohl zu niedrigeren Systemkosten als auch CO_2-Emissionen – allerdings wiederum auf Kosten einer im Vergleich höheren lokalen Netzbelastung. Die zusätzliche Betrachtung von zukünftig weitverbreiteter Elektromobilität ändert dieses Bild nicht grundsätzlich - was gleichzeitig einen wichtigen Hinweis für die Stabilität der Ergebnisse mit Blick auf parametrische Unsicherheiten darstellt.

Contents

List of Figures

List of Tables

List of abbreviations

Abbreviation	**Explanation**
BS	Battery storage
CAPEX	Capital expenditures
CNC	Capacity-based network charges (peak-coincident network capacity utilization charges)
COE	(Market-based) costs of electricity
COP	Coefficient of performance
DSO	Distribution system operator
EEG	Erneuerbare-Energien Gesetz (German Renewable Sources Act)
EV	Electric vehicles
ETS	Emissions Trading Scheme
FCOE	Full costs of electricity
FI	Feed-in (of electricity produced by PV)
FIT	Feed-in tariff
FLH	Full load hours
GS	Grid supply
HP	Heat pump
HS	Heat storage
LCOE	Levelized costs of electricity
MVF	Market value factor
NUTS	Nomenclature of territorial units (geocode standard regulated by the EU)
OPEX	Operating expenditures
PV	Photovoltaics
RCA	Regulatory cost component
RES	Renewable energy source(s)
RL	Residual load
SC	Self-consumption
SCR	Self-consumption ratio
SDG	Sustainability Development Goal (by the United Nations)
TSO	Transmission system operator
VA	Virtual prosumer association
VNC	Volumetric network charges

1 Introduction

The transition of the global energy system towards net zero CO_2 emissions requires the deployment of renewable energy sources (RES) such as on- and off-shore wind energy, hydro energy, bio energy, and photovoltaics (PV). In a broader context, a high penetration of RES contributes to the implementation of multiple UN Sustainability Goals (SDGs) such as climate action (SDG 13), the reduction of air pollution (SDG 3), universal access to affordable and clean energy (SDG 7), sustainable transport systems (SDG 11), and sustainable use of natural resources (SDG 12); see United Nations, 2022. However, actual investment in and implementation of new RES capacities is constrained by scarce resources, such as the following

- **Financial resources:** The cost structure of RES projects significantly differs from that of conventional power plants.[1] In contrast to conventional power plants, RES projects are dominated by investments costs with variable production costs being close to zero. The associated financial uncertainties for RES investors are therefore of a different nature – related to the variable nature of generation, such as production profiles and full load hours.
- **Land use:** The energy density of RES is generally lower compared with conventional power plants. As a result, energy production from RES requires larger areas of land and could conflict with competing interests in land use.
- **Local ecosystems:** Certain RES projects entail interventions in local ecosystems such as potential disturbances of marine life by off-shore wind parks or environmental impacts from the construction of high-voltage transmission systems.
- **Acceptance:** RES generally enjoy broad social support; however, in some cases, there is local protest and resistance to the actual implementation of RES projects. In Germany, this is compounded by a relative high population density, a historically strong environmental movement, and the federal structure of political decision-making.

These factors have a particular impact on large-scale RES projects and complicate their implementation. This raises the question of how small-scale, *distributed*[2] RES units such as household PV in combination with battery storage can be most effectively promoted and integrated into the energy system. These small-scale systems, as installed on rooftops,

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[1] Referring to the thermal production of electrical energy from fossil resources such as coal, lignite, oil, and natural gas; or nuclear fission.

[2] A precise definition of distributed energies is provided in Section 2.1.1.

for instance, do not lead to additional land consumption, do not represent an environmental impact and are widely accepted. Nonetheless, the comparison of large-scale versus small-scale projects is clearly not to be understood as *either–or* but as *both–and*. This becomes all the more apparent when considering the magnitude of the challenge presented by the energy transition. Not only the residential sector and the trade, commerce and services sector, with final electricity consumptions of 667 TWh and 365 TWh (Germany, 2020), respectively, but also the mobility sector, with a final energy consumption of 635 TWh (Germany, 2020), must be fully decarbonized.[3] Large parts of the decarbonization of these sectors will be realized through electrification, including the widespread use of heat pumps and electric cars. By contrast, in 2021, 49 TWh was generated by PV[4], of which less than 9 TWh originated from small-scale PV.[5]

Despite steadily decreasing levelized costs of electricity (LCOE), most small-scale RES investors still rely on subsidizing instruments to fully refinance the investment costs of their projects. Of the existing regulatory instruments, feed-in tariffs (FITs) are among the most widely used worldwide; see Masson et al., 2016. In Germany, they are implemented on the legal basis of the German Renewable Sources Act (Erneuerbare-Energien-Gesetz (EEG)). However, FITs do not act in isolation “in a regulatory vacuum,” but rather interfere with the wholesale market price and other retail price components such as network charges. These interferences can result in distortion effects that create unintended incentives for the actual investment in and operation of small-scale RES systems. Given large enough numbers of households investing in small-scale RES projects, such distortions can lead to inefficiencies in the overall system, i.e., higher system costs, and greater inequality in household burdens. Following the above outline of the general context of this thesis, Section 1.1 elaborates on the objectives of the present work.

1.1 Objectives of this work

This work aims to understand how large numbers of households owning and operating distributed small-scale RES systems in the future will affect the energy system, in terms of both efficiency, i.e., total system costs, and resulting distributional effects. These households that both produce and consume energy are oftentimes referred to as energy *prosumers*. A precise definition of this term is provided in Section 2.1.2. Prosumers

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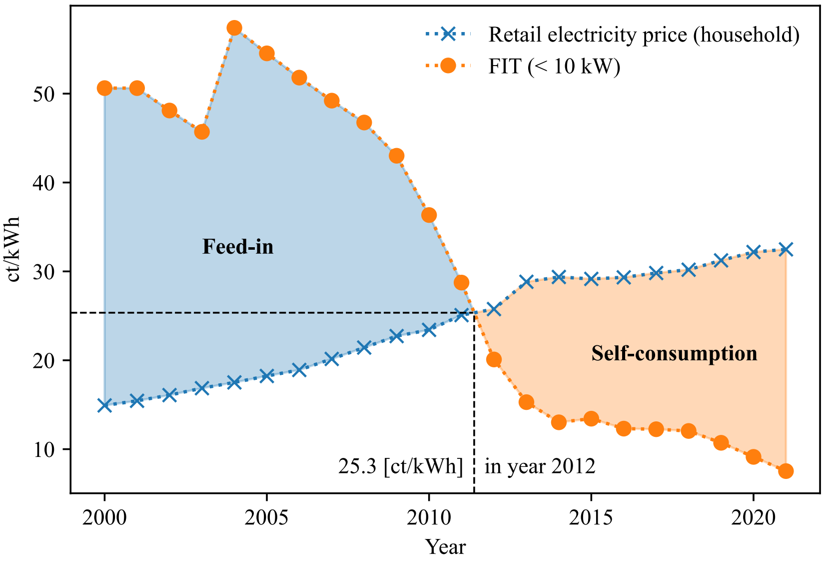
[3] All figures from Umweltbundesamt (2022). *Endenergieverbrauch 2020 nach Sektoren und Energieträgern.* URL: https://www.umweltbundesamt.de/daten/energie/energieverbrauch-nach-energietraegern-sektoren#entwicklung-des-endenergieverbrauchs-nach-sektoren-und-energietragern (visited on 09/22/2022)

[4] Figures from AGEB AG Energiebilanzen, 2022

[5] 1.4 million small-scale units with a total of 9.3 GW installed capacity, see Bundesnetzagentur, 2022, and average full load hours of 910 h/a, see Wirth, 2021, corresponding to an annual small-scale PV production of approximately 8.5 TWh, neglecting curtailment.

must make their investment decisions under uncertainties with regard to the variable character of energy production, such as production profiles, achievable full load hours, and overall wholesale market factors (prices). In Germany, the EEG aims to compensate for these uncertainties and to enable stable private investment decisions in RES by means of fixed FITs. These FITs would ideally compensate for the difference between investment costs and actual market value of the energy produced from the investment. Accordingly, prosumers will direct their investment and operating behavior to this instrument. At the same time, the RES support costs incurred are volumetrically allocated to the end consumers, e.g., as a levy on the amount of energy withdrawn from the public grid. However, since 2012, the actual incentive for many prosumers has changed; see Figure 1-1. In the case of small-scale PV, with FITs being lower than retail electricity price, prosumers no longer seek to feed their generated electricity into the public grid, but rather to increase their *self-consumption* to avoid expensive external electricity purchases. A precise definition of self-consumption is provided in Section 2.1.3.

Fig. 1-1: Average retail electricity prices and FITs for households and small-scale PV systems $<10\ \text{kW}_\text{p}$. Germany, 2000 – 2021. Colored areas illustrate the respective incentives for prosumers to feed the generated electricity into the grid (blue), or to consume it themselves (orange). Data sources: Bundesministerium für Wirtschaft und Klimaschutz, 2022a (FITs) and Bundesministerium für Wirtschaft und Klimaschutz, 2022b (retail prices).



More abstractly, the interference of FITs with other electricity price components affects prosumer behavior in terms of both investment and operation decisions. As a result, prosumers who seek to maximize self-consumption change their residual load[6], i.e., both

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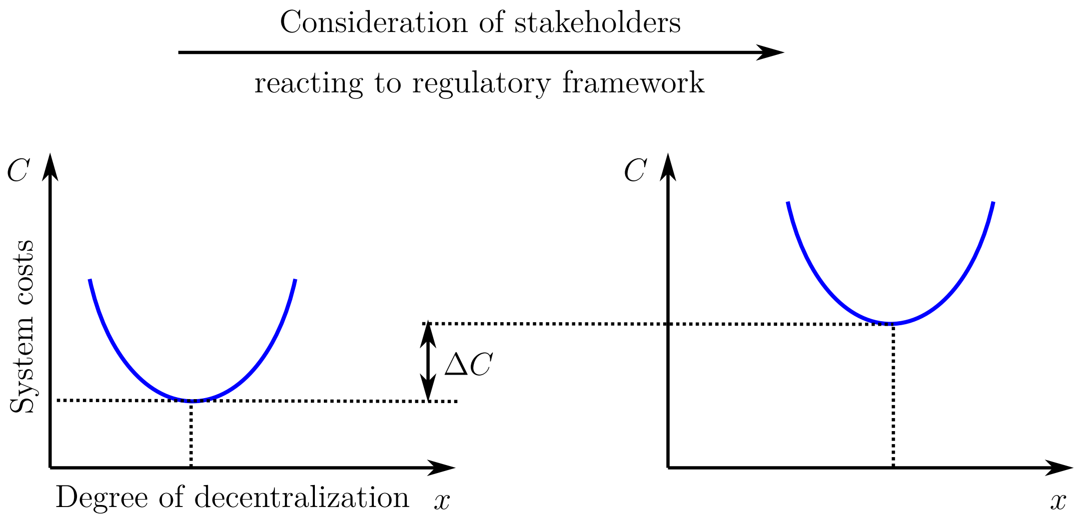
[6] Load minus generation.

the annual demand and the residual load profile. In small numbers, these changes in the residual loads of prosuming households are negligible at the aggregated (system) level. However, if millions of households become prosumers using PV, batteries, and further flexibility options, this will have a noticeable impact on the energy system as a whole. Prosumers can constitute an essential source of private capital for RES investments that benefit the system as a whole. However, the maximization of self-consumption in highly decentralized energy systems beyond a critical threshold could, for instance, result in storage redundancies and non-optimal integration of other (non-PV) RES, leading to additional system costs. As a consequence, the total system optimum shifts, depending on the operation modes of the numerous distributed units; see Figure 1-2.

Fig. 1-2: Schematic illustration of the shift in the total system optimum as a consequence of prosumers responding to the regulatory framework. In response to the incentives set by the regulatory framework, prosumers seek to maximize self-consumption, which shifts the actual degree of decentralization of the system to the right (higher degree). Correspondingly, inflexible (from a system perspective) battery operation could lead to an increase in total system costs ΔC.



To date, little research has considered these effects due to the behavior of distributed actors, as is demonstrated in Section 2.2. In the future, however, highly *decentralized* energy systems will have feedback effects between prosumers and the overall system that must be considered. A precise definition of *decentralization* is provided in Section 2.1.1. The behavior of prosumers as a response to the underlying regulatory market framework affects not only the system as a whole but also particular stakeholder groups. This is because high levels of self-consumption lead to certain refinancing tasks, such as for the infrastructure and operation of the network, being passed to the remaining traditional consumers. These consumers consequently face higher specific and absolute electricity costs, e.g., due to increasing network charges. This ultimately leads to a redistribution of burdens between different household groups that could reinforce socioeconomic inequalities and thus, at worst, jeopardize the general acceptance of the energy transition. Moreover, specific decisions made by prosumers to operate their flexibility options could either relieve the distribution network or result in additional stress on the network. For instance, depending on the simultaneity of prosumer behavior, local nodes of the distribution network could be thermally stressed by constructive interference of feed-in peaks from prosumer households.

In other words, prosumers affect the energy system at different scales – the household level, the distribution network level, and the wholesale market level. The motivation for this work is thus to study prosumers' behavior as a response to the underlying regulatory market framework and the resulting effects at different scales of the energy systems in detail. For this, a quantitative analysis is used that maps system effects, regulatory framework features, and strategic prosumer behavior in a closed and consistent manner. The present work thereby aims to reveal the weaknesses of the present regulatory framework with regard to the smart integration of prosumers. In addition, possible adjustments for the future regulatory framework are discussed and examined on the basis of this analysis.

1.2 Structure of this work

This work is a cumulative thesis composed of three scientific journal contributions, organized as follows: In the introduction (Section 1), the general scope of this work is provided, including definitions of key terms and concepts, identification of the research gap, and derivation of the research question. This section concludes by presenting the overarching research question for the analyses of the three papers. In the literature review (Section 2), central terms and concepts are defined. With this foundation, the central research gap can then be identified to define the research question of the present thesis. The subsequent main part of the work comprises three peer-reviewed journal papers, Schick and Hufendiek, 2023; Schick, Klempp, et al., 2022; and Schick, Klempp, et al., 2021 (Section 3, Section 4, and Section 5). Each section is preceded by a description of the independent contribution of the author of this thesis to the respective paper. This work concludes with a comprehensive discussion of all results (Section 6), including the limitations of this work and suggestions for future research.

2 Literature review

2.1 Definition of terms

This work is laid out in the context of the increasing *decentralization* of energy systems through the increased use of *distributed*, small-scale RES. This process involves numerous stakeholders, some of whom are active market participants, referred to as *prosumers*. The behavior of these prosumers as a response to the underlying regulatory market framework leads to effects at different scales of the energy systems. This work seeks to study these effects in detail. Before this analysis is carried out, central terms and concepts of this work are defined.

2.1.1 Decentralization and distributed energies

With respect to small-scale RES in particular, the terms “distributed” and “decentralized” are used in the literature; see Alanne and Saari, 2006, for instance. These terms are partly used synonymously but in the present work, they are differentiated according to the scale to which they refer. That is, *decentralization* refers to the overall energy system as a whole, whereas *distributed energies* refers to the individual, local application.

Definition of distributed energies

According to Ackermann et al., 2000, an electric power system is distributed if it is directly connected to the distribution grid or to the local (home) grid. For the authors, other dimensions, such as the size of the generation facility, are not necessarily direct prerequisites.[7] This approach has been adopted and slightly modified by others; see Pokojski et al., 2007. For the present work, we adopt this definition but differentiate it further by considering other relevant dimensions of distributed energies.

First, the control concepts of distributed energies are of importance for this work. This is because distributed energies not only are a source of generation, but also contribute *flexibility options* to the system. In principle, three prototypical flexibility operation modes can be distinguished as follows; see Schick et al., 2021.

1. **Application-oriented:** Distributed flexibilities can operate for individual purposes, such as profit maximization or (possibly leading to the same result) self-consumption maximization, depending on the regulatory framework.

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[7] Regardless of possible correlations.

2. **Network-oriented:** Distributed flexibilities can operate (distribution) network-beneficially, for example reducing peak coincident network utilization (peak shaving).

3. **Market-oriented:** Distributed flexibilities can operate market-beneficially, for example to leverage portfolio effects for optimal RES integration at the wholesale market (system) level.

It is important to note that this distinction is not necessarily mutually exclusive. This is because, first, by definition, every mode of operation is application-oriented. The pertinent question is whether, and to what extent, congruence can exist between application-oriented and system-oriented (network or market) operation.

Second, distributed energies can be differentiated by technology type. In the present work, the primary focus is on PV systems in combination with battery storage (see Sections 3, 4, and 5). However, in addition, Paper B (Section 4) considers household heat pumps and thermal storage. From the perspective of the heating sector, a heat pump resembles a distributed generator[8], from the perspective of the electricity sector, it is a distributed consumer. Moreover, Paper C (Section 5) considers e-mobility, which is not a distributed energy source but an important distributed application that could exacerbate certain impacts of distributed generation and storage, such as the change of residual load profiles.

Third, unit size serves as another differentiating criterium. The present work exclusively considers PV systems <10 $\mathrm{kW_p}$. This system size limit is motivated by historic regulatory requirements of the EEG – specifically, the complete exemption from taxes and levies for small-scale PV under 10 $\mathrm{kW_p}$.[9] The available rooftop areas themselves also represent an upper system limit for distributed PV in the residential sector.

Definition of decentralization

For the definition of *decentralization*, we refer to Alanne and Saari, 2006, and to the studies of Bauknecht et al., 2015 and Matthes et al., 2018.

Alanne and Saari, 2006, introduce the concept of the "degree of decentralization," meaning that an energy system is typically not entirely centralized or decentralized but "somewhere in between," where distributed energies and central power plants operate in parallel. Rather than providing an explicit mathematical expression, Alanne and Saari, 2006, list certain parameters as indicators of the extent to which a system is centralized or decentralized, including the ratio between consumption nodes and generation units

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[8] Even though, technically, it does not generate heat but merely shifts it.

[9] The exemption limit for the EEG levy has been raised to 30 $\mathrm{kW_p}$ since 2021; see Federal Law Gazette Part 1, 2020, No. 65.

(modularization), the “average distance between a unit and a consumption node” (spatial distribution), and the level of “interaction between units (and consumption nodes)”. Bauknecht et al., 2015, and Matthes et al., 2018, adopt this approach in principle, using slightly different dimensions to evaluate the degree of decentralization of a system. In particular, they add the dimension of the respective market coordination mechanisms. For instance, a system could be coordinated decentrally by distribution system operators (DSOs) or centrally via uniform wholesale market prices.

As a synthesis of these studies, we define a *decentralized energy system* in terms of four dimensions: grid connection level, spatial distribution, degree of modularization, and market coordination mechanism. Each of these dimensions can have a stronger centralized or a more decentralized character, as illustrated in the following list:

- **Grid connection level:** How many generation units of the power system are connected to the distribution grid (and how many to the transmission grid)?
- **Spatial distribution:** How much of local/ regional demand is covered by local/ regional production (where local/ regional refers to the respective size of the underlying sub-balancing groups)? A quantitative measure for this can be provided by the total amount of self-consumption within a sub-balancing group; see Section 2.1.3.
- **Degree of modularization:** What is the ratio of the number of generation units to the number of consumption units within the considered energy system? A quantitative measure for this can be provided by the prosumer penetration ratio.
- **Market coordination mechanism:** Are there multiple local markets and prices or one central market into which distributed energies are integrated and in which uniform pricing takes place?

This thesis encompasses three peer-reviewed papers studying energy systems with different degrees of decentralization according to the definition of the present work. With respect to the grid connection level, all three papers consider residential small-scale PV systems that are exclusively connected to the distribution network. With respect to the spatial distribution and the degree of modularization, Paper A (Section 3) is based on the development of the German electricity system over the past 20 years, with approximately 1.4 million small-scale PV systems, i.e., a 4% prosumer penetration ratio; status 2021. Papers B and C (Sections 4 and 5), respectively, are model-based studies suggesting energy systems with significantly higher spatial distribution and degree of modularization with up to 30 million small-scale PV systems, corresponding to prosumer penetration ratios of up to 75%. With regard to the market coordination mechanism, all three papers assume a central wholesale market with uniform, non-locational pricing. In addition, Paper C also considers locational network charges that are oriented to the actual capacity utilization of the local grid; see Section 5. Although this does not represent a local market, it does represent a consideration of local characteristics of the system users.

2.1.2 Prosumers

As mentioned before, the transition of energy systems towards higher shares of RES correlates with an increasing number of distributed energies that (energy) prosumers invest in and operate. The term prosumer is derived from the terms *pro*-duce and con-*sume* and thus represents the most elementary properties of this stakeholder group. For the purpose of this work, however, this definition does not sufficiently describe the essence of prosumers in the context of energy systems. A definition that abstracts the crucial feature of prosumers is given by Bremdal, 2011, who defines prosumers as follows:

> "*More precisely, prosumers are consumers that resonate with the market, responding in real time to supply and demand signals to optimize a product for personal benefits.*"

In summary, prosumers are characterized as consumers with an active market participation role. This role not only includes the production of energy, but extends beyond that by including, for instance, the provision of flexibility. However, it is not central to the definition of prosumers whether they are formally direct participants in the wholesale market. Even without formal market involvement, prosumers interact ("resonate") with the surrounding energy system through active management of their dispatchable components such as electric and thermal storage. Whether they react to real-time prices or whether their behavior is aimed at maximizing their self-consumption is of no relevance to their status as prosumers. The key point is that prosumers can actively influence their residual load to a certain extent through their behavior. Moreover, strictly speaking, this definition also includes pure load flexibilization in the context of classical demand side management. However, without providing a formal mathematical expression, a prosumer is generally understood to be a stakeholder who has a relevant minimum level of influence over their own residual load. For the residential sector, this usually requires ownership or possession of some type of generation and/or storage units.

While prosumers are often thought of only as owners and operators of distributed (small-scale) PV systems, the term should actually include technologies that directly relate to distributed generation and create additional degrees of freedom in the control and operation of prosumer applications. Such technologies comprise not only electric storage (battery systems) but also applications from other energy sectors, such as heat pumps including thermal storage, and electric cars. In this work, the focus is on combined PV and battery systems (in all three papers). Additionally, heat pumps and thermal storage are considered in detail in Section 4, whereas some aspects of e-mobility are considered in Section 5.

Moreover, the term prosumer does not refer exclusively to the private sector, it is in principle independent of unit size and includes commercial and industrial stakeholders as well. Commercial or industrial prosumers do not necessarily need to possess their own power generation units, but can take an active market role through demand side management. However, in this work, the focus is solely on private households.

The crucial point for this work is that prosumers can make choices about how they invest in distributed energies and related applications and how they operate their flexibility options, depending on (regulatory) market incentives. These incentives can be monetary or non-monetary. In this paper, we focus solely on monetary incentives, which, according to the current state of science, account for a major part of prosumer decision building; see Allan and McIntyre, 2017, for instance.

2.1.3 Self-consumption

An important variable in the context of prosumers is self-consumption, which refers to prosumers' ability to consume part of the energy they generate themselves – either directly or indirectly via (battery) storage systems. Today, the monetary incentive for self-consumption is often based on regulatory benefits, in particular, the full or partial exemption from surcharges and levies for self-produced and -consumed electricity.

A prosumer's self-consumption SC can be derived from two perspectives; see Schick et al., 2022, for instance. For the sake of simplicity, the following equation assumes a simple PV and battery system. From a production perspective, SC is the annual amount of electricity produced by the prosumer's PV power and battery storage system, $P_{PV} + BS_{prod} - BS_{sto}$ (under consideration of curtailment), less the amount of electricity that is fed into the public grid FI. From a demand perspective, SC is the prosumer's demand D_{el} less the amount of electricity withdrawn from the public grid GS as shown in Equation 2-1.

$$\begin{aligned} SC &= \sum_{t \in T} \underbrace{P_{PV}(t) + BS_{prod}(t) - BS_{sto}(t) - FI(t)}_{\text{as expressed from a production perspective}} \\ &= \sum_{t \in T} \underbrace{D_{el}(t) - GS(t)}_{\text{as expressed from a demand perspective}} \end{aligned} \tag{2-1}$$

The self-consumption ratio SCR is a relative value $\in \{0, 1\}$, defined by the absolute amount of self-consumption divided by the total production of the prosumer PV system, as indicated in Equation 2-2.

$$SCR = \frac{SC}{\sum_{t \in T} P_{PV}(t)} \tag{2-2}$$

To be precise, Equations 2-1 and 2-2 depict a cumulative self-consumption (ratio) within a certain time period T, whereas the summands in Equation 2-1 represent the momentary self-consumption at time t.

2.2 Research gap and research question

Section 2.1 introduces central terms and concepts, Section 2.2 now identifies the research gap and defines the research question. In a meta study involving 359 studies addressing system modeling of decentralized energy autonomy, Weinand et al., 2020, describe a lack of much needed consideration of local stakeholders and distributed energy systems as follows:

> "*By analysing the studies, many improvements for future studies could be identified: the studies lack an analysis of the impact of autonomous energy systems on surrounding energy systems. In addition, the robust design of autonomous energy systems requires higher time resolutions and extreme conditions. Future research should also develop methodologies to consider local stakeholders and their preferences for energy systems.*"

In other words, Weinand et al., 2020, identify a gap in present system modeling to represent multiple scales simultaneously: the individual level ("autonomous energy systems"), which for the purposes of the present work translates simply into household level; the local level of the surrounding distribution network; and the global level of the overall wholesale market ("surrounding energy systems"). Furthermore, to realistically consider individual stakeholder behavior, especially strategic prosumer behavior ("local stakeholders and their preferences"), it is also essential to depict characteristic features of the regulatory framework. This is because private households are generally not part of the wholesale market, they operate in the retail market and face retail prices. In the first half of 2022, network charges alone accounted for 22% (8.08 ct/kWh) of the retail electricity price on average (37.14 ct/kWh); see BDEW Bundesverband der Energie- und Wasserwirtschaft, 2022. These retail prices – and their avoidance through self-consumption – largely determine prosumers' actual behavior. Moreover, the prosumer business case generally depends on regulatory support schemes such as feed-in tariffs.

Tab. 2-1: Literature review (compact version; non-exhaustive)

			Scale		
	Regulatory framework		Household	Local	Global
	RES support schemes	Network charges	Strategic prosumer behavior	Impact on network	Impact on system
Bayod-Rújula et al., 2017	✓	✓	×	×	×
Bird et al., 2013	✓	✓	✓	×	×
Borenstein, 2017	✓	✓	✓	×	×
Broering and Madlener, 2017	✓	✓	✓	×	×
Chao, 2011	×	×	✓	×	×
Chen et al., 2012	×	×	✓	×	×
Doulamis et al., 2018	×	×	✓	×	✓
Eid et al., 2014	✓	✓	✓	×	×
Klein et al., 2019	×	×	✓	×	(✓) [a]
Lu et al., 2019	×	×	✓	×	(✓) [b]
Masson et al., 2016	✓	✓	×	×	×
McKenna et al., 2017	✓	×	✓	✓	(×) [a]
Parag and Sovacool, 2016	×	×	✓	(✓) [c]	(✓) [c]
Parvania et al., 2013	×	×	(✓) [d]	(✓) [d]	(✓) [d]
Perez-Arriaga and Knittel, 2016	×	✓	✓	✓	(×) [a]
Ramyar et al., 2020	×	×	✓	×	✓
Ruhi et al., 2018	×	×	✓	×	×
Schill et al., 2017	✓	×	(✓) [e]	×	✓
van der Stelt et al., 2018	✓	×	✓	×	×
This thesis	✓	✓	✓	✓	✓

[a] Exogenous wholesale market price time series

[b] No consideration of price signal effect on prosumers

[c] Qualitative analysis only

[d] Focus on aggregator profit maximization

[e] No end customer (retail) prices

Thus, to realistically represent prosumers and their interactions with the surrounding energy system, it is essential to integrate the depiction of the following aspects into energy system modeling: relevant characteristics of the underlying regulatory framework such as RES support schemes and network charges; strategic prosumer behaviour (individual scale); and analyses of the impacts of prosumer behavior on the surrounding distribution network (local scale) and on the overall system at the wholesale market level (global scale). Table 2-1 overviews the coverage of these aspects in the existing literature, revealing gaps particularly in the consideration of interferences between the individual stakeholder level and the overall system level. Paper A (Section 3) contains a detailed review of relevant literature addressing the general analysis of distributional effects from RES promotion based on empirical data as well as spatial analysis of regulatory benefits and costs; Paper B (Section 4) covers relevant literature addressing the analysis of strategic prosumer behaviour, regulatory framework analyses as well as system model analyses. Finally, Paper C (Section 5) explores relevant literature addressing the general theory of network charge design, analysis of local distribution network systems with high distributed generation, and an analysis of system impacts.

Table 2-1 demonstrates that in the existing literature, a coherent view of the impact of prosumers on the energy system at different scales (household, distribution network, wholesale market), under a realistic consideration of the underlying regulatory framework, is currently lacking. As an interim conclusion, the following gaps are identified in current research regarding the interference between prosumers and the energy system:

- There is no realistic and consistent depiction of the underlying regulatory framework and the actually incentivized prosumer behavior in energy system models, at least not in a consistent quantitative manner.
- The focus is mostly on one particular scale of the energy system, and a coherent, simultaneous quantitative depiction of all three scales – individual (household), local (distribution network) *and* system (wholesale market) level – is lacking.
- The logical break between the retail market in which prosumers act and the wholesale market is insufficiently addressed in energy system modeling, resulting in an unrealistic depiction of the flexibility provided by investments in and operation of distributed storage (or, more generally, flexibility options).

Moreover, many of the above mentioned aspects have been analyzed only qualitatively. For instance, numerous studies discuss the effect of cross-subsidization through FITs and the resulting high specific and absolute charges to non-prosumers as prosumers increasingly “decouple” from the energy system through self-consumption. However, robust quantitative analyses on the basis of a system model is currently missing.

The research question

The objective of the present work is to contribute to filling the research gaps identified in the previous section. Hence, the research question of the present work is defined as follows:

Research question

> "*How does large-scale prosumer penetration in combination with deployment of distributed energies affect the overall energy system at different scales – household level, distribution network level, and wholesale market level?*"

The research question is to be answered by means of

- considering the strategic behavior of prosumers incentivized by the regulatory framework, such as self-consumption maximization,
- putting a major focus on the interferences between individual prosumer behavior and the wholesale market, and a minor focus on impacts at the distribution network level,
- examining both prosumer decision making on investments in distributed energies and the operation of these systems.

One the one hand, this research objective is formulated relatively abstractly to answer the question in a generally valid way; see Section 4 (Paper B) and Section 5 (Paper C), in particular. On the other hand, to derive quantitative results, certain parts of the modeling require concretization, namely the regulatory framework. Hence, throughout this thesis, we assume a regulatory framework oriented to Germany, including FITs and volumetric regulatory price components such as network charges. The legislative foundation for FITs in Germany is the EEG, which many countries have adopted in its general structure since its introduction in Germany. Thus, the conclusions of the present work are transferable to other countries, in principle.

Based on the abstract formulation of the research question, more specific questions are derived and attributed to the respective scale. Leading questions regarding the individual scale (household level, H) that drive the analyses of the present work are

- **H1:** *How and by how much do prosuming households striving to maximize their self-consumption impact the retail electricity costs for purely consuming households?*
- **H2:** *What does the spatial distribution of net benefits associated with the EEG look*

like?

Leading questions regarding the local scale (distribution network, N) that drive the analyses of the present work are:

- **N1:** *By how much can the local distribution network be relieved through grid-oriented prosumer behaviour?*
- **N2:** *Can benefits for the distribution network, e.g., reduction of peak-coincident network capacity utilization, and benefits for the wholesale market, e.g., optimal RES integration, coincide or do they conflict?*

Leading questions regarding the global scale (system/ wholesale market level, S) that drive the analyses of the present work are:

- **S1:** *What levels of self-consumption are, in principle, system-compatible? By how much do total system costs increase when prosumers strive for higher levels of self-consumption?*
- **S2:** *What is the total system cost difference between price-reactive and static operation of distributed flexibilities?*

The ultimate question of this work addresses the extent to which widespread elements of the existing regulatory framework, such as FITs in combination with volumetric RES support costs (levies) and volumetric network charges, create a divergence between the possible modes of distributed flexibility operation as detailed in Subsection 2.1.1. In particular, it explores the extent to which the individual prosumer optimum as an actual reaction to the regulatory framework differs from the theoretically achievable overall system optimum. In conclusion, using the example of network charges, a possible further development of the regulatory framework is discussed in view of better convergence between prosumer- and system-oriented behavior. Next, we outline how the three journal papers contribute to answering the aforementioned questions.

Approach and logical flow

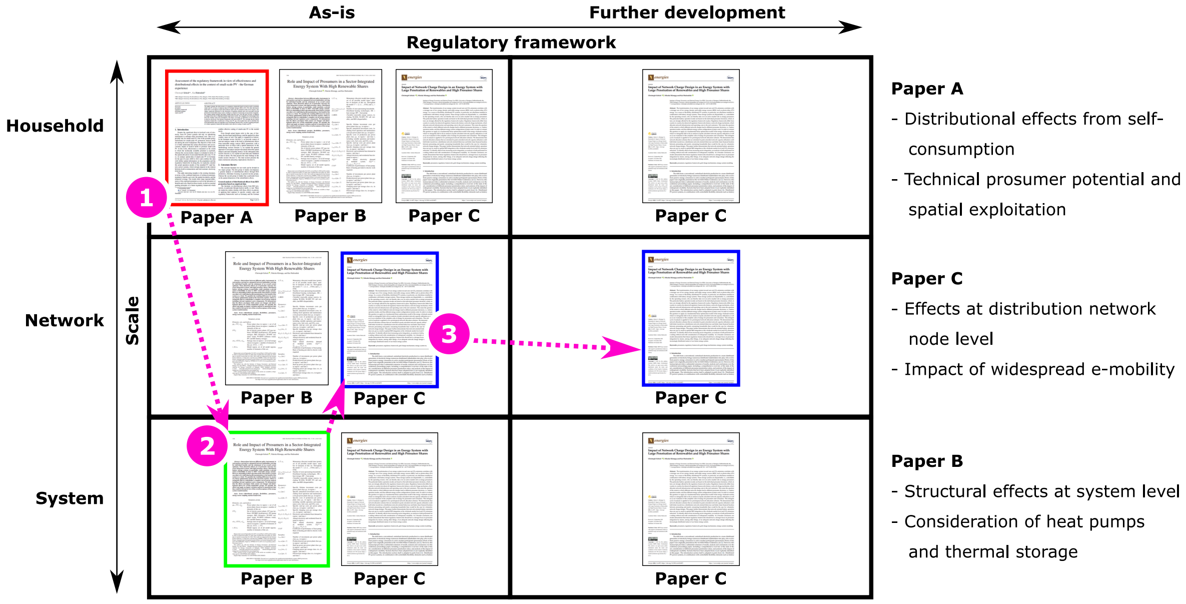
Figure 2-1 and Figure 2-2 illustrate the logical flow of the investigation. Each paper has a clear focus related to the scale of analysis. Moreover, Paper A and Paper B (Sections 3 and 4) are based on the present existing regulatory framework, whereas Paper C (Section 5) analyzes potential further developments of the regulatory framework.

- Paper A (Section 3): Focus on the individual stakeholder level

- Paper B (Section 4): Focus on the wholesale market level
- Paper C (Section 5): Focus on the distribution network level

The elements connecting the three papers are the assumption of a total system size oriented to Germany regarding the number of households and technical potential for small-scale PV, the assumption of a regulatory framework with FITs and volumetric regulatory price components oriented to the EEG, and the technological focus on residential PV and battery systems.

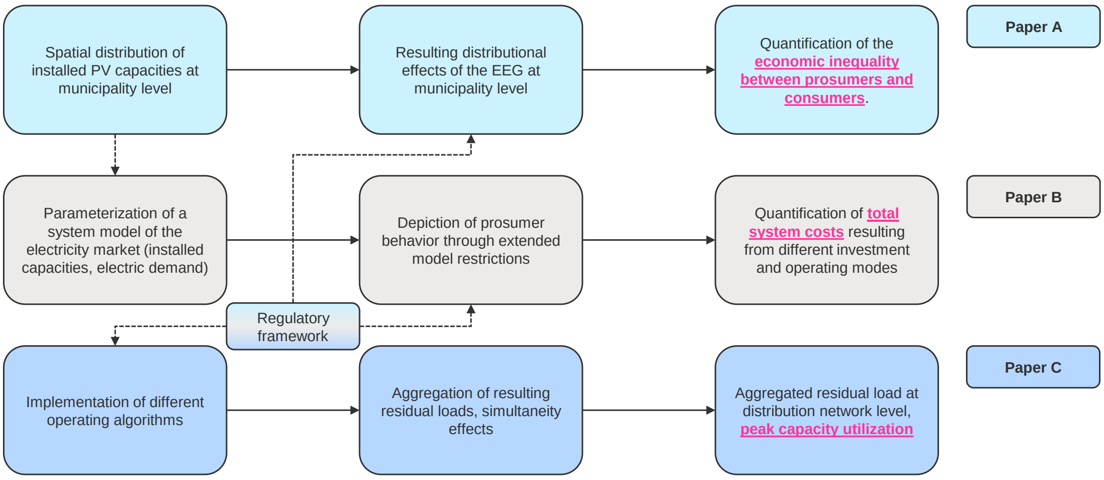
Fig. 2-1: Overall modelling approach. Numbers in circles and arrows represent the logical order of analysis steps.



2.2.1 Paper A: Focus on the distributional effects from the emergence of prosumers

Paper A starts with an analysis of the existing prosumer potential (small-scale rooftop PV potential) and its regional exploitation in Germany between 2000 to 2021. The main focus is on the distributional effects resulting from today's regulatory framework, the EEG, considering the historical development of feed-in tariffs, EEG levy, retail prices and PV and battery investment costs. In particular, it examines and quantifies the role that self-consumption already plays in redistributing regulatory benefits and costs. Methodologically, this study is an empirical analysis supplemented by the necessary modeling of the operating model of distributed storage and the resulting self-consumption rates. The

Fig. 2-2: Flow chart of the overall analysis.



paper hence sheds light on an important part of the problem definition by quantifying the current prosumer impact on the power system in terms of distributional consequences. In addition, the estimated prosumer potential serves as a guide for modeling highly decentralized energy systems in Papers B and C. The questions to be answered in this paper are H1 and H2.

2.2.2 Paper B: Focus on structural effects at system level for systems with high prosumer shares

Paper B addresses the research question raised in Paper A, regarding the distributional effects resulting from the emergence of prosumers in the context of the current regulatory framework. The aims are to (a) abstract the investigation and (b) extend the investigation by considering system effects. These aims are achieved by abstracting the characteristic features of the EEG (feed-in tariff and EEG levy) and network charges to a generic regulatory framework. In this way, feed-in tariffs, EEG levies (RES support costs) and network charges are derived by connecting system quantities to corresponding end-customer price components. The analysis is performed by means of a linear optimization model of the electricity market with different model constraints to depict possible prosumer behavior as a response to the underlying regulatory framework. The main objective of this paper is to investigate and quantify structural system effects of a general nature due to prosumer behavior concerning the investment in and operation of distributed PV in combination with relevant, possibly sector-integrating applications, including electric and thermal storage, and heat pumps. More precisely, Paper B examines the extent to which prosumers “shift” the system optimum by their behavior in response to the regulatory framework, i.e., cause additional costs in the overall system. As an extension to Paper A, Paper B distinguishes fundamentally different prosumer operating strategies corresponding to different levels of market integration (full, partial, and none). Since the results of this paper cannot be directly empirically validated, the robustness of the results is evaluated through a parameter variation analysis. Even though the main focus is on the interference between the individual prosumer behavior and the resulting total system effects at the wholesale market level, a short part of the paper is devoted to resulting (distribution) network effects. This is the link to Paper C. The questions to be answered in this paper are S1 and S2.

2.2.3 Paper C: Extending the scope to network effects and analysis of peak capacity charges

Paper C goes deeper into the analysis of network effects, with a particular focus on the impact of increasing self-consumption. In contrast to Paper B, the starting point of the analysis in Paper C is not a system view, but a detailed representation of the residual load of prosumer households derived from measured data of single-family households with a temporal resolution of 15 min. Different control algorithms are implemented and investigated. In consideration of simultaneity effects, the prosumer residual load profiles are then aggregated at the distribution grid node (and wholesale market) level to analyze the resulting capacity utilization of the network. In a sense, Paper C forms a methodological parenthesis to Papers A and B in that it analyzes the effects of large-scale prosumer penetration at all three scales in a closed-loop analysis: the household level, grid level, and wholesale market level. In contrast to Papers A and B, Paper C not only analyzes prosumer effects for the existing regulatory framework but also considers further developments, namely peak capacity network charges. Such a network charge design based on peak coincident capacity utilization sets a different control incentive for the operation of the distributed flexibilities and therefore leads to new system states at all three aggregation levels considered. Moreover, to better understand the effects of increasing sector integration, possible effects of widespread e-mobility are also considered. In particular, the complex interplay between market- and network-oriented behavior is analyzed with respect to system costs, prices, and resulting CO_2 emissions, however, this topic can only be touched upon in passing within the scope of this dissertation and is hence not dealt with comprehensively. The questions to be answered in this paper are N1 and N2.

3 Paper A

3.1 Author contributions

Table 3-0 shows the contributions of the co-authors of Paper A, based on the representative roles according to the Contributor Roles Taxonomy (CRediT).[10]

Tab. 3-0: Author contributions for Paper A: Assessment of the regulatory framework in view of effectiveness and distributional effects in the context of small-scale PV - the German experience

	Paper A	
	Christoph Schick	Kai Hufendiek
Conceptualization	✓	
Methodology	✓	
Formal analysis	✓	
Software	✓	
Data curation	✓	
Validation	✓	
Visualization	✓	
Writing - original draft	✓	
Writing - review & editing	✓	✓
Supervision		✓

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[10] See https://credit.niso.org/ for further details.

3.2 Assessment of the regulatory framework in view of effectiveness and distributional effects in the context of small-scale PV - the German experience

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Assessment of the regulatory framework in view of effectiveness and distributional effects in the context of small-scale PV—The German experience

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ABSTRACT

This paper evaluates the effectiveness of a regulatory framework based on feed-in tariffs to promote small-scale PV on basis of empirical data for Germany between 2000 to 2021. We show that feed-in tariffs have so far failed to exploit the technical small-scale PV potential evenly across regions. This implies significant differences in the allocation of regulatory benefits and costs associated with the promotion of renewable energy sources, leading to a situation of increasing socioeconomic inequality: few counties benefit strongly and many counties bear the costs. Over the past 20 years, in addition to margin effects due to disproportionately high feed-in tariffs, this inequality has increasingly been driven by steadily rising self-consumption. This leads, on average, to differences of over 40 percent in effective electricity costs between households with and without PV. We conclude that the current regulatory framework is insufficient to bring solar PV up to the needed level and to distribute the associated benefits and costs equitably across households. Based on this, we derive guiding principles of a future regulatory framework that enables more effective scaling of small-scale PV.

1. Introduction

The transition of the global energy system towards zero net CO_2 emissions requires the deployment of renewable energy sources (RES). Actual investment in and implementation of new RES capacities is generally constrained by the availability of financial resources, while the implementation of large-scale RES projects is further complicated by competition for land use and acceptance. This draws particular attention to the question of how small-scale, distributed RES projects such as household PV systems can be most effectively promoted and integrated into the energy system. Small-scale PV systems require private investors to make investment decisions under uncertainties regarding variable production profiles, achievable full load hours, and overall wholesale market factors (prices). Moreover, despite the significant decrease in levelized costs of electricity, most PV power systems still rely on subsidizing instruments to refinance their investment costs. To compensate for these uncertainties and hitherto incomplete competitiveness, regulatory support instruments are used to enable stable private investment decisions. Of the possible policy instruments for (small-scale) PV promotion, feed-in tariffs are among the most widespread. The idea is to guarantee small-scale PV investors fixed feed-in tariffs over an agreed-upon period of time. To do so, the regulator would ideally compensate for the difference between prosumer PV investment costs and the market value of the electricity produced from the PV investment. However, feed-in tariffs do not act as an isolated instrument, but rather interact with the wholesale price and other regulatory end price components, which could lead to unintended inefficiencies and distortions.

Thus, the objective of this work is to better understand the actual effectiveness and socioeconomic impact of feed-in tariffs to promote small-scale PV. In this work, effectiveness is measured as the extent to which the technically available potential is exploited. Meanwhile, the socioeconomic impact is evaluated in terms of the spatial allocation of associated benefits and costs. To do so, we analyze spatial data of small-scale PV in Germany for the past 20 years (2000 to 2021) and combine this data with further spatial information on the population and the regulatory framework. In doing this, we explicitly consider the actual operation models of the installed PV (and battery) power systems, which strongly depend on the relation between feed-in remuneration and end-customer electricity retail price.

The use of spatial analysis provides important insights. First, regional differences in small-scale PV installations become clearly visible and are an important indication of existing inefficiencies that are not discernible when viewed on a spatially aggregated basis. Second, the spatial analysis enables the identification of “white spots” with regard

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to exploitation of the existing technical potential. Third, in conjunction with an analysis of the temporal development, it is also possible to determine the extent to which regional differences in the distribution of benefits and costs are purely statistical or structural in nature.

This study adds interesting insights to the existing literature in terms of the combined depiction of technical potentials, regulatory benefits *and* costs, the spatial resolution, and the temporal coverage. The results show large regional differences in the exploited potentials as well as the allocation of benefits and costs. Based on these results, we derive essential guiding principles of a future regulatory framework that enables effective scaling of small-scale PV to the required levels. Even though numerical values of this study refer to the case of Germany, the methodology developed could be applied to other country cases as well. Notwithstanding the fact that certain features of the German EEG may not apply to other countries, our analysis essentially assumes only two features that exist in a similar form in other countries: feed-in tariffs and volumetric regulatory price components that privileged end-users can avoid through self-consumption. These features apply to many countries, particularly in the EU; see Masson et al. (2016). The question of transferability of this study to other countries is therefore a question of the availability of the necessary technical and socioeconomic data; see Section 6.2 for further discussion.

The paper is organized as follows: In the literature review (Section 2), we provide the context of relevant analyses made in the field of distributional effects from renewable energy sources (RES) promotion, with a particular focus on those with a spatial dimension. In the methodology section (Section 3), we explain the general approach of our analysis and provide details about the spatial analysis and inequality metrics used. In the subsequent data section (Section 4), we explain all of the data used and validation of the data in detail. We then present the main findings in the results section (Section 5). The final section presents the main conclusions and policy implications (Section 6) as well as a discussion of the limitations and future work.

2. Literature review

The relevant literature for our work can be divided into three major groups. The first group of studies provides an overview of existing RES support schemes and analyzes the corresponding general socioeconomic effects. The second group of studies particularly focuses on the socioeconomic effects of the Renewable Energy Sources Act (EEG), which forms the legal basis for RES promotion by means of feed-in tariffs in Germany. The third group of studies specifically addresses the spatial dimension of the redistributive effects of feed-in tariffs.

2.1. General analysis of RES support schemes and socioeconomic effects

Masson et al. (2016) provide a general overview of different RES support schemes and analyze different regulatory instruments for RES promotion in 24 countries. For Europe, the Council of European Energy Regulators (2021) provides comparative data on support schemes for RES, including feed-in tariffs, feed-in premiums, investment grants, and green certificates. Both Masson et al. (2016) and Council of European Energy Regulators (2021) provide an excellent overview of existing RES support instruments. However, the evaluation of their actual effectiveness and distributional consequences is not part of their scope. Bird et al. (2013) provide general analyses on the effects from RES promotion and the emergence of prosumers. The authors analyze the impact of prosumer business models on the cost allocation to end users under different rate designs. In contrast to our work, the authors are primarily concerned with conceptual considerations rather than rigorous empirical analysis. Schick et al. (2022) conduct further work on the general nature of distributive effects of feed-in tariffs in the presence of high shares of prosumers with small-scale PV and battery systems. The authors show that individual household optimization could result in additional costs for the energy system, and significant extra burdens for non-prosuming households. Nevertheless, unlike the present study, their work is more theoretical in nature and does not apply empirical data. Bertsch et al. (2017) analyze the profitability of PV and battery investments for the country cases of Germany and Ireland. The authors identify strong incentives for self-consumption in both countries that could lead to distributional issues between prosumers and traditional consumers, with the latter possibly having to pay ever higher per unit charges. However, the distributional consequences are only discussed qualitatively and not assessed quantitatively, as is the case in our study. Sabadini and Madlener (2021) also address the effect of increasing self-sufficiency associated with distributed PV-battery systems, analyzing the economic feasibility of grid defection in detail. They find that, while 100% self-sufficiency is not economically feasible, maximization of self-consumption at an individual household level or within a peer-to-peer network appears to be an economically favorable prosumer choice. In contrast to the present study, their analysis is based on prototype residential households rather than empirical data.

2.2. Analysis of distributional effects of the EEG

The literature on the distributional effects of the EEG is vast, and the socioeconomic measures that are studied are numerous, ranging from employment impacts to energy security. The focus of our work is on household income effects, which are studied in various papers. The relevance of these studies goes beyond the scope of Germany. This is because the EEG has served as a model for RES support schemes worldwide and many countries have adopted its basic structure; see Masson et al. (2016) and Council of European Energy Regulators (2021). In their study, Frondel et al. (2010) review the economic impacts of the promotion of RES through the EEG. Based on their analysis the authors find that the EEG has failed to provide adequate market incentives for a cost-effective adoption of RES in order to achieve the associated goal of CO_2 reduction in combination with a positive net employment effect, technology innovation, and promotion of energy security. Moreover, they highlight the potentially inefficient interaction between the EEG and the overarching European Union (EU) Emissions Trading Scheme (ETS) in reducing CO_2 emissions. Unlike the present study, the focus is not on the distributional effects of the EEG and the authors do not aim to spatially disaggregate their results. Grösche and Schröder (2014) address the question of how to fairly distribute the costs to promote RES for the country case of Germany. By applying different inequality indices such as Gini, Theil, and Atkinson index, they demonstrate that the EEG leads to regressive feed-in tariffs, i.e., tariffs that redistribute income shares from lower-income households to higher-income households. Frondel et al. (2015) perform an empirical analysis of distributional effects for the country case of Germany, focusing on low-income households. In their analysis they quantify how much of a low-income household's income is allocated to power and consider possible mitigation measures such as direct cash transfers. Both Grösche and Schröder (2014) and Frondel et al. (2015) base their study on data sets of approximately 6700 and 7800 households, respectively, focusing on differentiation by income class. Nevertheless, in contrast to our work, they do not draw on a complete empirical data set for the whole of Germany including spatial information for approximately 1.4 million households with small-scale PV.

2.3. Spatial analysis of distributional effects of feed-in tariffs

Grover and Daniels (2017) analyze social equity issues associated with the distribution of feed-in tariff policy benefits for the country cases of England and Wales. While Grover and Daniels (2017) provide valuable insights into possible socioeconomic explanations for the distribution of regulatory profits, our work goes well beyond their analysis in that we also consider supply and investment costs. Furthermore, their analysis does not address the role of storage and storage operation models in order to increase self-consumption, which is part of our work. Többen (2017) provide another valuable analysis of social distribution effects originating from the promotion of RES on basis of the EEG. Using multiregional price models, the authors demonstrate that the EEG is associated with substantial regressive distributive effects affecting the disposable household incomes. Their analysis encompasses a regional dimension at the level of the 16 federal states, whereas we perform a more detailed spatial analysis at the municipality level. Moreover, Allan and McIntyre (2017) use a spatial econometric model to analyze local socioeconomic factors for the country case of Great Britain. These factors explain regional variation in small-scale PV adoption in the presence of feed-in tariffs. The authors conclude that the adoption of household PV is driven by financial motives and opportunities rather than "green sentiment". Their focus is on identifying explanatory factors for differences across income groups rather than quantifying the resulting socioeconomic inequalities.

3. Methodology

The methodology involves three main steps. In the first step, we analyze the spatial development of installed PV capacities at the municipality level for Germany between 2000 and 2021. Moreover, we compare the actual installed capacities with the respective local technical potentials. Based on this, in the second step, we derive the distribution of net regulatory benefits associated with the promotion of RES on the basis of the EEG at the municipality level. Technically, this is the main analysis step, including an assessment of the operating modes of the respective PV power systems (feed-in driven or self-consumption driven) and estimation of the effect of distributed storage. Third and finally, we measure the resulting economic inequalities using established inequality measures, including Gini coefficients as well as absolute income differences at the household level. In addition, in order to address parametric uncertainty, we employ lower and upper bounds whenever parameters are not directly available but need to be estimated; see Section 4 for more details. The respective outputs therefore correspond to ranges instead of singular points.

3.1. Spatial analysis of small-scale PV

To define the term "municipality", we refer to the nomenclature of territorial units for statistics (NUTS). NUTS is a geocode standard regulated by the EU, which refers to subdivisions of countries; see Eurostat (2020). In this work, municipality level refers to the 401 German regions at the NUTS3 level. For the spatial analysis of installed PV capacities (numbers), the electrical capacities of the installed PV units are cumulatively summed up (counted) per NUTS3 region and year, based on the data of Federal Network Agency (2022); see Section 4. Moreover, we divide the installed PV capacities Cap into three size clusters: small-scale, equivalent to $Cap \leq 10$ kW$_\mathrm{p}$, mid-scale, equivalent to 10 kW$_\mathrm{p}$ $< Cap \leq$ 500 kW$_\mathrm{p}$, and large-scale, equivalent to $Cap >$ 500 kW$_\mathrm{p}$. The differentiation is primarily oriented to the respective regulatory framework, namely the EEG. The 10 kW$_\mathrm{p}$ limit has defined the complete exemption from surcharges and levies up until 2021.[1] Therefore, in the past, practically all rooftop installations have been sized ≤10 kW$_\mathrm{p}$, even in cases where roofs would have allowed for larger installations.

The analysis of the available PV rooftop potential represents a deliberately simple approach to estimate the available technical potential for small-scale PV. For a more detailed analysis, the works of Lödl et al. (2010) and Mainzer et al. (2014) are recommended. For our purposes, we are interested in robust results in the context of a self-contained analysis as a basis for the subsequent investigation of the distribution of net regulatory benefits. Despite the relative simplicity of our analysis, we demonstrate that our results fit well into the range of existing literature values. For the spatial analysis of small-scale rooftop PV potentials, we apply census data from the Federal Statistical Office (2011), to obtain the cumulative numbers of detached houses, semi-detached houses, terraced houses, and other types of houses per NUTS-3 region, denoted by $n_i(b)$, where b and i represent building type and NUTS3 region, respectively. In order to derive the technical PV rooftop potential P_{RT} in a selected NUTS-3 region, we assume that each building type has an average rooftop area A, of which a certain proportion is available for rooftop PV, represented by the rooftop factor $F_{RT}(b)$. Introducing ϕ as a conversion factor between area [m^2] and PV peak capacity [kW$_\mathrm{p}$] yields the technical PV rooftop potential as given in Eq. (1).

$$P_{RT}(b) = \sum_{i \in \mathrm{NUTS3}} n_i(b) \cdot A_i(b) \cdot F_{RT}(b) \cdot \phi \tag{1}$$

Mean and upper bound values for F_{RT} are based on Lödl et al. (2010). Lower bound values represent an installation density that is reduced by 20% in comparison to the mean value. Regarding ϕ, Lödl et al. (2010) actually assume a higher value of 0.15 kW$_\mathrm{p}$/m^2 than used in this study. However, this approach neglects limiting interference factors that need to be taken into account, e.g., edges of the roof, chimneys, and rooflights. Therefore, commercial solution brokers assume more realistic values of 8 to 10 m^2 per kW$_\mathrm{p}$, corresponding to the range of ϕ used in this study; see Doormann (2022), for instance. In general, we tend to make comparatively conservative assumptions about the technical rooftop potential so as not to report artificially low values for potential utilization. All assumptions applied are summarized in Table A.1 in Appendix.

3.2. Spatial analysis of regulatory benefits and costs

Next, we consider the distribution of regulatory benefits and costs. To quantify the true net benefit (or disadvantage) of households with PV (prosumers) over households without PV (consumers), we compare the annual costs of electricity for a consumer household to the respective costs for a prosumer household. In the following, the terms "net regulatory benefit" and "net prosumer benefits" always refer to the gross benefits (from feed-in, self-consumption) less the associated costs (investment costs).

The annual electricity costs for a consumer household are the product of their annual consumption D and the (average) retail electricity price λ. For the prosumer household, the annual electricity costs comprise three components: their external supply costs C^{Pros}_{Supply}, their annualized PV (and battery, if applicable) investments costs C^{Pros}_{Inv}, and the benefit from feed-in remuneration P^{Pros}_{FIT}, with opposite sign; see Eq. (2).

$$\begin{aligned}
C^{Cons}_{Total} &= D \cdot \lambda \\
C^{Pros}_{Total} &= C^{Pros}_{Supply} + C^{Pros}_{Inv} - P^{Pros}_{FIT} \\
C^{Pros}_{Supply} &= (D - SCR \cdot Cap \cdot FLH) \cdot \lambda \\
C^{Pros}_{Inv} &= Cap \cdot c_{Inv} \cdot AF \\
P^{Pros}_{FIT} &= (1 - SCR) \cdot Cap \cdot FLH \cdot FIT
\end{aligned} \tag{2}$$

The external supply costs of the prosumer are reduced by the proportion of electricity, which is self-produced and -consumed, given by the self-consumption ratio SCR times the installed PV capacity Cap times the full load hours FLH. The annualized investment costs C^{Pros}_{Inv} are the product of installed PV capacity Cap, specific investment costs c_{Inv}, and annuity factor AF. The regulatory profit P^{Pros}_{FIT} is the product of electricity fed into the public grid, i.e., the electricity produced by the installed PV system less the self-consumed portion, and the specific feed-in tariff FIT. FIT depends on the installation date. Therefore, both λ and FIT represent time series in our analysis. For the sake of readability, we refrain from explicitly showing their time dependence in this paper.

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[1] The so-called de minimis threshold has been raised to 30 kW$_\mathrm{p}$ since 2021; see Federal Law Gazette Part 1, 2020, No. 65.

Next, we analyze the difference Δ between the annual electricity costs of consumers and prosumers, which corresponds to the net prosumer benefit; see Eq. (3).

$$\begin{aligned} \Delta &= C^{Cons}_{Total} - C^{Pros}_{Total} \\ \Delta &= \underbrace{Cap \cdot (FLH \cdot FIT - c_{Inv} \cdot AF)}_{\text{Margin effect, } \Delta_{Margin}} \\ &+ \underbrace{SCR \cdot Cap \cdot FLH \cdot (\lambda - FIT)}_{\text{Self-consumption (SC) effect, } \Delta_{SC}} \end{aligned} \qquad (3)$$

We conclude that Δ is driven by two different mechanisms: a margin effect as a result of feed-in tariffs that could overcompensate for PV investment costs, and a self-consumption (SC) effect, i.e., a reduced third-party power purchase due to self-consumption. In the expression of Eq. (3) it is also clear that a prosumer household will feed-in all the energy produced, i.e., $SCR = 0$, as long as $FIT \geq \lambda$. It should be noted that prosumer households in this study face a gross metering scheme based on the EEG. Moreover, the full feed-in of electricity incentivized in the case of $FIT \geq \lambda$ refers only to the billing scheme applied. In most cases, the physical flow of electricity will actually deviate from the accounting method, at least at certain times.

Analogue RES support schemes encompassing FIT in combination with volumetric RES support costs are commonly used worldwide. Thus, even though numerical values always refer to the country case of Germany, our analysis should be methodologically transferable to other countries.

Regarding the retail electricity price, $\lambda = \lambda(\ldots)$ comprises various components, above all the wholesale price, sales margins, regulatory components such as the EEG levy and network charges, and taxes. Network charges can vary considerably from region to region. However, to isolate the distributional effects of the EEG, we use a regionally constant λ in this paper; see Table A.4. In this way, all calculated differences can be directly attributed to the effect of the EEG. That said, spatial variation in retail prices is substantial; see the corresponding discussion in Section 6.3. So far, the analysis is based on the level of individual households. We have omitted corresponding indices for the sake of better readability.

Next, we analyze the resulting effects at a higher level of aggregation. That is, we assess the consequences for average household electricity costs $\overline{C}_i$ at the NUTS3 level. Taking into account the respective prosumer penetration ratio ρ_i, where i represents a specific region (NUTS3 level or Germany as a whole), the average household electricity costs at the NUTS3 level are obtained from Eq. (4).

$$\begin{aligned} \overline{C}_i &= (1 - \rho_i) \cdot \overline{C}^{Cons}_{Total} + \rho_i \cdot (\overline{C}^{Cons}_{Total} - \overline{\Delta}_i) \\ \overline{C}_i &= \overline{C}^{Cons}_{Total} - \underbrace{\rho_i \cdot \overline{\Delta}_i}_{\delta_i} \end{aligned} \qquad (4)$$

In the equations above, $FLH(\ldots)$ and $SCR(\ldots)$ are both functions that depend on multiple parameters such as the specific system size of the respective PV system and the location (latitude). We analyze this in more detail in the following subsections.

3.2.1. *Self-consumption ratios*

Smaller systems usually allow for higher SCR, whereas larger systems come with lower SCR. For this work, we derive the corresponding achievable values for SCR as a function of the system size based on the work of Schick et al. (2021). For the derivation of SCR values, an annual prosumer household electricity consumption of 4000 kWh is assumed, without further spatial differentiation; see Section 6.3 for further discussion. Moreover, the achievable SCR of a PV system is possibly impacted by the presence of electrical storage. In the case of Germany, distributed solar home storages have become relevant since 2013. The impact of storage on the SCR of a PV system of capacity x is taken into account according to the respective ramp-up curve; see Eq. (5).

$$SCR(x,t) = \overline{SCR}(x) \cdot (1 + \alpha \cdot \beta(t)) \qquad (5)$$

In this equation, $\overline{SCR}$ represents the SCR without storage, and $\beta(t)$ represents the share of small-scale PV units that are installed in combination with distributed home storage systems in year t. The actual values for $\beta(t)$ used in this work are based on Figgener et al. (2018) and extrapolated where necessary; see Table A.4. Explicit values for β are available only for the years 2015 to 2017. Before and including 2013, battery storage played only a marginal role, hence, $\beta = 0$ for these years. Values for 2018 and subsequent years are linearly extrapolated with $\frac{\partial \beta}{\partial t} = 0.04$. The 2014 value is assumed to be two third of the 2015 value.

An analysis based on the work of Schick et al. (2021) demonstrates that for systems larger than 6 kW, the achievable SCR can typically be doubled with home storages, i.e., $\alpha = 1.0$ as the mean value assumption.[2] Moreover, α is set to 0.75 for the lower bound and to 1.25 for the upper bound. A summary of the $\overline{SCR}$ values used in this work is provided in Table A.2.

For the modeling of SCR we further consider the relationship between the respective FIT of the system and the end-customer electricity retail price λ. Generally, for $FIT \geq \lambda$, feed-in of produced electricity is economically favorable, corresponding to $SCR = 0$. This applies for small-scale PV units installed before 2012; see also Eq. (3).

3.2.2. *Full load hours*

The FLH are a function of the spatial position of the installed PV units, mainly of their respective latitudes. The values used in this work are based on long-term (30-year) average data for the global radiation as provided by Deutscher Wetterdienst (2022). The data is further validated by Wirth (2021), stating that PV roof systems achieve full load hours of 910 on average in Germany, which fits our assumptions well. Table A.3 in the Appendix provides a summary of the values applied for this study.

3.3. *Inequality metrics*

To quantify inequality, we use established inequality metrics throughout this work. These metrics include Gini coefficients and absolute (cost) deltas.

The Gini coefficient measures the inequality among a distribution of values – typically different levels of income – with a value range between 0, corresponding to perfect equality, and 1, expressing maximal inequality among values. In this work we apply the Gini coefficient for both the distribution of installed (small-scale) PV capacities per NUTS3 region and the distribution of net regulatory benefits. For this purpose, the 401 NUTS3 regions are used as underlying classes for the respective frequency distributions.

In a graphical representation using Lorenz curves, the Gini coefficient G is equal to the area A divided by the area $A + B$ as illustrated in Fig. 1.

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[2] The analysis is based on a linear optimization model to maximize self-consumption for a prosumer household with an annual electricity demand of 4000 kWh and PV system size varying from 6 to 10 $\mathrm{kW_p}$ in steps of 1 $\mathrm{kW_p}$. Optimization with and without a battery storage of 6 kWh content size results in different self-consumption ratios, corresponding to values for α ranging from 0.99 to 1.03.

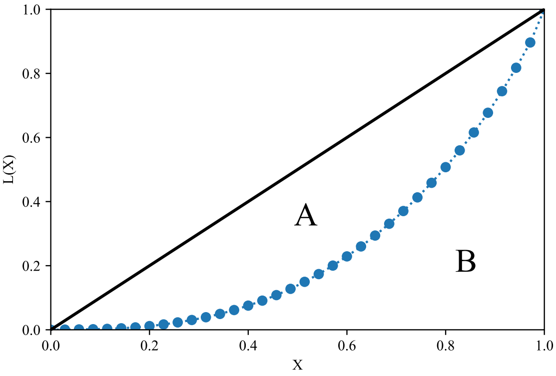

Fig. 1. Example of Lorenz curve $L(x)$ (dotted, in blue) and line of equality (in black).

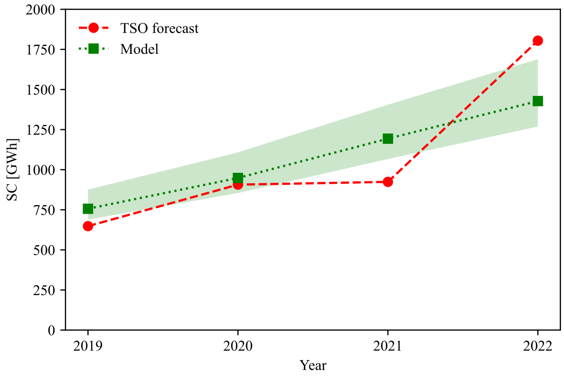

Fig. 2. Validation of data. Total amount of annual self-consumption modeled versus forecasted by TSOs. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

4. Data

This work relies on multiple sources for data input. The spatial data of installed PV systems is based on the publicly available market master data registry from Federal Network Agency (2022). This data encompasses nearly 2.3 million records of individual PV units. For this work, we take into account the following technical characteristics per unit: net nominal power (used as input for Cap), federal state, municipality, municipality key, postal code, city, commissioning date, and distribution system operator (DSO) status. Moreover, we assign the respective NUTS3 regions as well as the geocoordinates (latitude) of the units via their postal codes. For the analysis, we only take into account units with positive DSO status, corresponding to a data validation of the respective records by the DSO. Model assumptions for SCR and FLH are summarized in Tables A.2 and A.3, respectively; see also Section 3 for further details. Household data on annual demand, see Federal Statistical Office (2021); electricity prices, see Federal Ministry for Economic Affairs and Climate Action (2022a); FIT and further EEG data, see Federal Ministry for Economic Affairs and Climate Action (2022b) and 50hertz; Amprion; Tennet; TransnetBW (2022), is publicly available and summarized in Table A.4. In addition, Table A.4 provides data on PV and battery storage investment costs based on Wirth (2021), Federal Government (2002) and publicly available solar industry information; see Kümpel (2022) and Bemmann (2021). Moreover, socioeconomic data of the building structure for the analysis of the technical PV rooftop potential is based on the Federal Statistical Office (2011).[3] Annuity factors AF are calculated assuming $n = 20$ payment periods (years), consistent with the EEG subsidy period, and interest rate (weighted average cost of capital) $i = 2.5\%$. This comparatively low interest rate is based on the average loan terms of the available subsidy programs for small-scale private PV investors over the last 20 years in combination with a comparatively low project-specific default risk and moderate return expectations of private owners.

4.1. Data quality and validation

With regard to data uncertainty, a fundamental distinction can be made between directly available data and estimated data (assumptions). The latter have the highest uncertainties. For the analysis of the technical small-scale PV potentials, this concerns data on available rooftop area A, rooftop factors F_{RT}, and conversion factors ϕ. To address these uncertainties, lower and upper bound estimates are applied for each of these quantities in this study; see Table A.1. Moreover, data uncertainty affects assumptions on SCR and FLH; see also Section 3, impacting the absolute amount of annual self-consumption. Corresponding lower and upper bound estimates are provided in the remarks of Eq. (5) and Table A.3. Data at the individual system level is not available for this study. Nonetheless, in their annual forecast of the EEG levy, the German transmission system operators (TSO) also estimate the total amount of self-consumption in Germany.[4] To our knowledge, this is the best available reference data to validate our model assumptions. Fig. 2 depicts the literature values of the TSO estimates (in red) compared to our modeling results (in green), demonstrating that our model results generally agree with the TSO values. The TSO forecast and our model match well especially for the 2020 value. The TSO forecast value for 2021 is striking, because it differs only slightly from the previous year, even though additional PV battery systems were installed during this period. Regarding the discrepancy in the forecast values for 2022, we assume that the data set used in this study, the market master data registry from Federal Network Agency (2022), is partly incomplete for 2021 due to late reporting, leading to an underestimation of the resulting total amount of self-consumption.

5. Results and discussion

5.1. Spatial analysis of small-scale PV

Fig. 3 depicts the installed PV capacities in Germany as of 2021, as total for the whole of Germany, and differentiated by size class (small-scale, mid-scale, and large-scale), revealing a couple of interesting aspects. By the end of 2021, a total of 60.7 GW (2.3 million units) of PV has been installed in Germany.[5] 9.3 GW (1.4 million units) are small-scale systems, 28.8 GW (0.8 million units) are mid-scale systems, and 22.5 GW (396 units) are large-scale systems. This means that small-scale PV may contribute to 60% of the total number of installed units, but only to 15% of total installed capacity, whereas the 396 largest units alone contribute to 37% of the total installed capacity.

Each size cluster has a strong spatial concentration. Small-scale PV and mid-scale PV are most commonly found in the south of Germany, and, to a lesser extent, in the northwest. Meanwhile, large-scale PV

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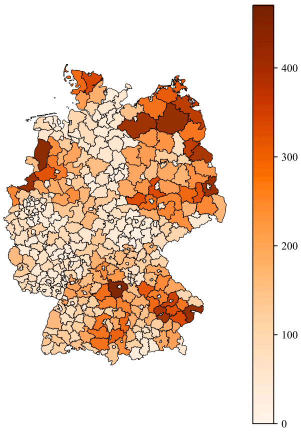
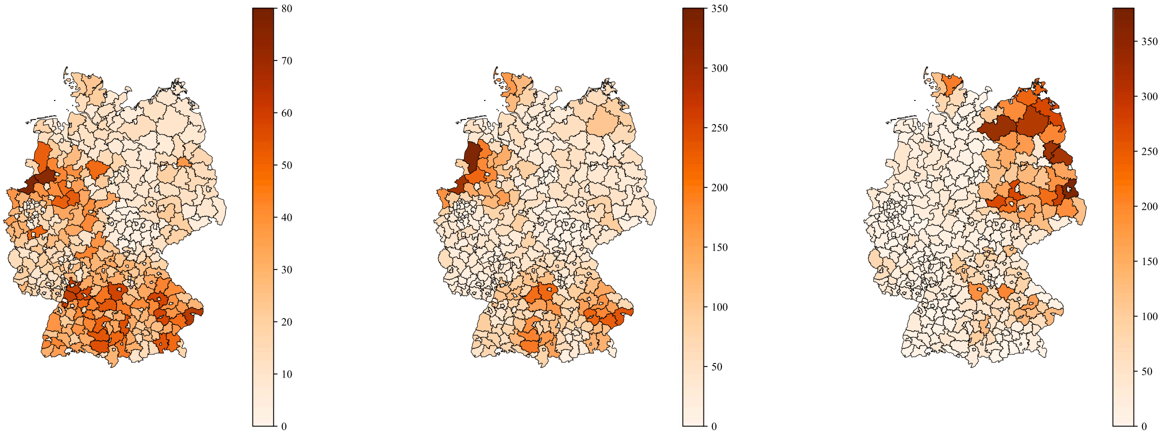
[3] The census is only conducted every ten years on a reference date. After the last census in 2011, the next one was to be conducted in 2021. However, it was postponed by one year due to the Corona pandemic and is therefore not yet available for this study.

[4] According to §61a No. 4 EEG.

[5] Absolute values for installed PV capacity in this subsection refer to gross capacity, excluding DSO status verification. From Section 5.2 onwards, we use net nominal capacity values for reasons of higher data quality, as described in Section 4.



(a) Total



(b) Small-scale (0 – 10 kW) (c) Mid-scale (10 – 500 kW) (d) Large-scale (> 500 kW)

Fig. 3. Installed PV capacities [MW] per NUTS3 region. Germany, 2021.

is clearly concentrated in the east of Germany. Regarding the small-scale units, a first hypothesis could be that the significant differences in spatial distribution stem from spatially different technical potentials. However, this is clearly contradicted by Fig. 4, which shows the technically available rooftop potentials and their regional exploitation. Compared to the actually installed capacities, the spatial concentration of the exploited technical potential is even stronger in the south, especially in some municipalities in the very southeast. In the municipalities with the lowest exploited potentials, less than 1% of the technical potential has been exploited so far, whereas in the municipalities with the highest exploited potentials, almost 18% of the technical potential has been exploited.

This spatially unequal distribution also accounts for the fact that, on average, over the whole of Germany, only a small fraction of 6% (5.6%) of the available rooftop potential has been exhausted so far.[6] In view of possible difficulties in realizing future large-scale projects, e.g. due to competition for land, this fact is an important indication that small-scale PV has so far not made the contribution to the energy transition that it could. Based on our analysis, we estimate the overall technical rooftop PV potential in Germany at 138 GW$_p$ (95 GW$_p$ to 163 GW$_p$), compared to 161 GW$_p$ estimated by Lödl et al. (2010) and 208 GW$_p$ by Mainzer et al. (2014). Therefore, our assumptions seem rather conservative.

An explanation for the regionally distinct exhaustion of the technical potentials, see Fig. 4(b) compared to Fig. 4(c), could be differences in the actual economically feasible potentials. That said, investment and installation costs cannot be regarded as an explanation of the regional differences—on the contrary, one would even tend to expect

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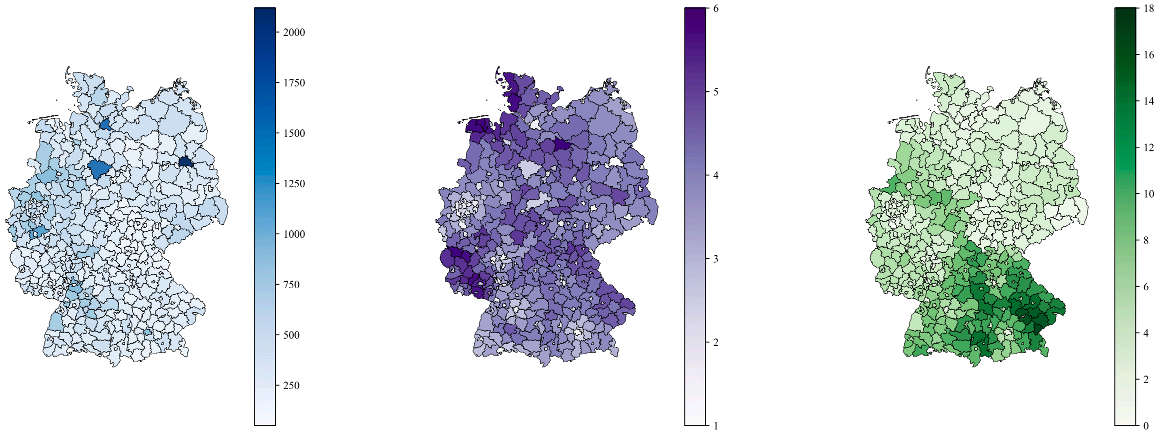
[6] Corresponding to the unweighted average of NUTS3 rooftop potentials. The weighted average of the rooftop potential exploitation can be calculated as follows: 7.5 GW of small-scale PV installed (only units with positive DSO status verification counted) versus an overall technical rooftop potential of 138 GW, corresponding to a potential exploitation of 5.4%.



(a) Small-scale PV rooftop potential [MW]

(b) Small-scale PV rooftop potential per household [kW/househ.]

(c) Small-scale PV rooftop potential exploited [%]

Fig. 4. Technical potential (exploited) for small-scale PV per NUTS3 region. Germany, 2021.

lower costs in the east than in the south. On the profit side, however, there are clear differences resulting from spatially different full load hours. Nevertheless, spatially different full load hours provide an inadequate explanation for the spatially unequally distribution of small-scale PV for two main reasons. First, with sufficient spatial and temporal averages to level local site factors, full load hours should strongly correlate with the global radiation. Nevertheless, one can observe that the spatial distribution of the global radiation, see Fig. A.1 in the Appendix, deviates significantly from the spatial distribution of the technical small-scale PV potential exploited, shown in Fig. 4(c). Especially in parts of the far east in the area around Chemnitz, Görlitz, Cottbus, and Frankfurt (Oder) one would expect significantly more small-scale PV on the basis of the long-term average of the global radiation, as illustrated by Fig. A.1 in the Appendix; see Deutscher Wetterdienst (2022). Second, the spatial concentration of large-scale PV in eastern Germany clearly inversely correlates with the respective achievable full load hours. This proves that there are framework conditions (in the case of large-scale PV: available land and low land prices; in the case of small-scale PV: disposable household income) that reinforce such concentrations independent of (technical) location factors. As an interim conclusion, we find that the EEG has so far failed to provide a sufficiently strong framework to promote PV nationwide and evenly across Germany.

5.2. *Spatial analysis of regulatory benefits and costs*

Next, we turn to the spatial allocation of net regulatory benefits resulting from the regional distribution of small-scale PV. While we have so far considered only a single point in time, i.e., the year 2021, we now consider the temporal development between 2000 to 2020 in addition to the spatial distribution.

To begin with, we analyze the amount of total net benefit that results from the EEG and is distributed among households in Germany. Fig. 5 shows the total net benefit of households with PV over those without PV, Δ, broken down by the underlying mechanisms: margin effect (in blue) due to feed-in tariffs, and SC effect (in red) due to savings in third-party electricity purchases including avoided EEG levies, network charges, and taxes. Fig. 5(a) shows the total effect (in MEUR) for Germany as a whole, whereas Fig. 5(b) shows the effect for an individual household (in EUR/household) as a calculative average across all prosumer households in Germany.

In absolute terms, the net benefit has grown over the past 20 years to more than 0.5 billion EUR today (mean value: 553 MEUR, lower bound: 444 MEUR, upper bound: 780 MEUR). Until 2012, this effect is exclusively based on the margin effect, i.e. disproportionately high feed-in tariffs compared to the corresponding PV investment costs. For 2005 to 2012 in particular, the effect has grown significantly, to 377 MEUR by 2012 (304–522 MEUR). This is a direct consequence of the political will to guarantee stable conditions for private small-scale PV investors, in combination with strongly decreasing investment costs due to corresponding learning curves in the production of the components. From 2012 onwards, the SC effect plays an increasing role. In 2021, 250 MEUR (220–298 MEUR), corresponding to a share of 45% (38%–50%) of the total net benefit of prosuming households is accounted for by the SC effect. Although the SC effect (still) makes up for slightly less than the margin effect, the SC effect will soon dominate, because older PV systems will no longer be subsidized, all newly installed systems are currently operated purely to maximize self-consumption and retail prices will remain high in the medium term. In particular, the retail price reducing effect of the abolition of the EEG levy is expected to be overcompensated for by other electricity price components, especially the wholesale price, grid charges, and taxes.[7]

Fig. 5(b) shows the effects at individual household level, i.e., the average net benefit of a prosuming household relative to a purely consuming household. In contrast to Fig. 5(a), the average net benefit of prosuming households peaks in 2009 at 727 EUR/household (581–1020 EUR/household), driven purely by the margin effect, and steadily declines since then. At the same time, the importance of self-consumption has been steadily increasing for individual households since 2012, driven by the continuous increase in external electricity purchase costs combined with decreasing feed-in tariffs. Since 2019, the margin effect for new plants is negative, i.e., these plants can refinance themselves through self-consumption only. In 2021, the average net prosumer benefit is 458 EUR/household (368–646 EUR/household), which is approximately 43% (35%–61%) less annual electricity costs than for households without PV. Moreover, with continuously rising external electricity prices, the gap between consuming and non-consuming households could widen again in the future, even despite disappearing margin effects at the individual household level.

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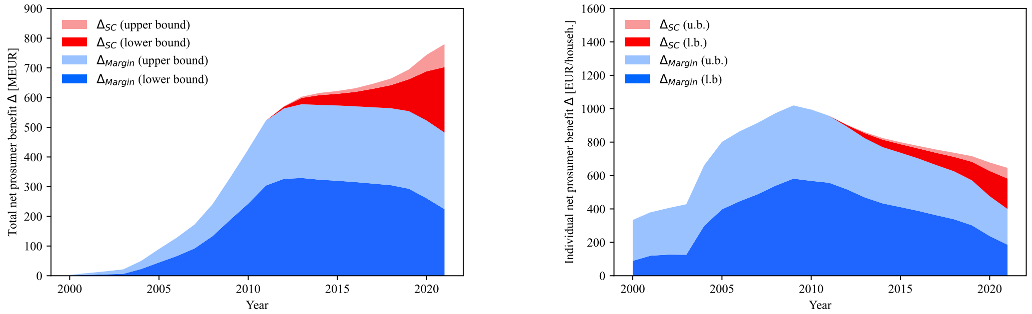
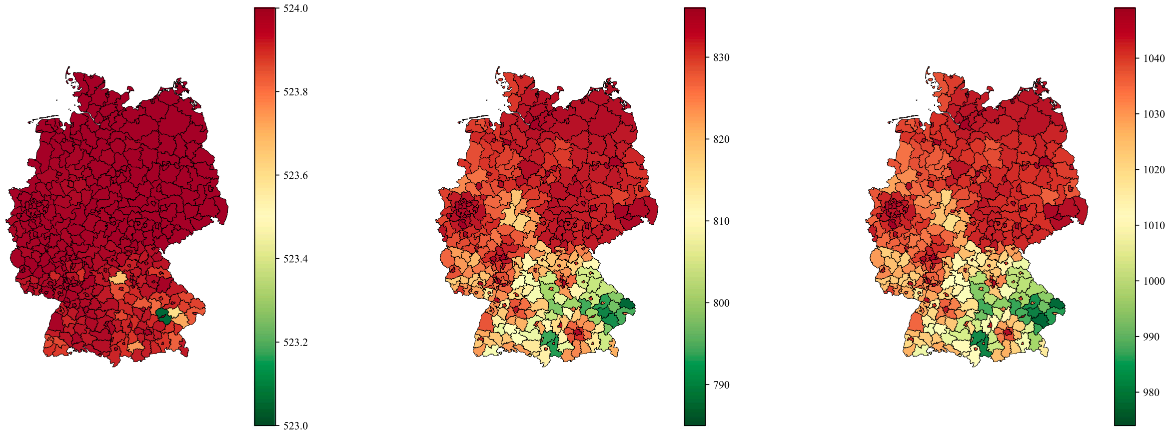
[7] As of April 2022, the EEG levy (3,72 ct/kWh) accounts for approximately 10 percent of the retail electricity price (37,14 ct/kWh); see BDEW (2022).



(a) Total Germany (b) Average household

Fig. 5. Net prosumer benefit Δ, (a), total in [MEUR] and, (b), average household in [EUR/household]. Germany, 2000–2021. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)



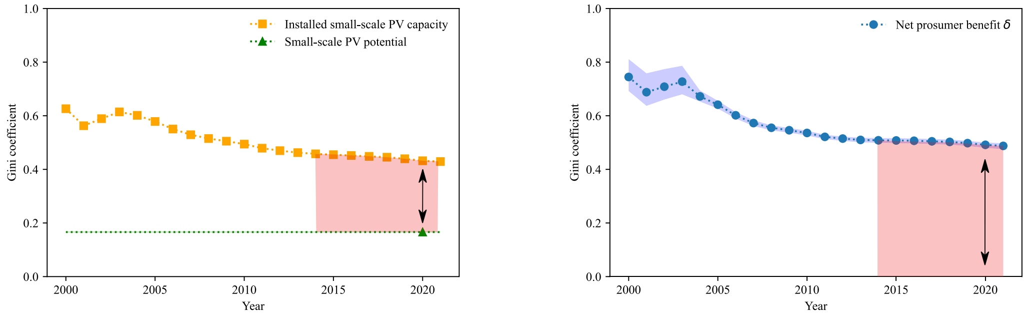
(a) 2000 (b) 2010 (c) 2020

Fig. 6. Distribution of average annual household electricity costs $\overline{C}_i$ per NUTS3 region [EUR/household]. Germany, 2000–2020. Only differences due to the EEG effect considered. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Next, we analyze the results of these inequalities between prosuming and consuming households at the NUTS3 level. The regional differences correspond precisely to the product of the individual household cost delta Δ and the penetration ratio of prosumer households within a municipality ρ, i.e., $\delta = \rho \cdot \overline{\Delta}$; see Eq. (4). Fig. 6 illustrates the development of the spatial distribution of net prosumer benefits over the past 20 years. For the sake of readability, only the mean values are given here. In 2000, at the beginning of the EEG, regional differences due to corresponding PV subsidies are still largely negligible. The differences at the NUTS3 level are in the range of a 1 EUR/household, with the overall span being 523 to 524 EUR/household. This is a direct consequence of the low penetration of (small-scale) PV at this point in time. In 2010, a clear bipartition can be seen in Germany. Few municipalities in the very southeast of Germany benefit most from comparatively low average household electricity costs (in green), whereas the majority of municipalities face higher annual electricity costs of up to 52 EUR/household (in red), with the overall span being 785 to 836 EUR/household. This bipartition persists structurally to the present. The spread between the most and least burdened municipalities has since increased further to as much as 75 EUR/household on NUTS3 average in 2020, with the overall span being 971 to 1049 EUR/household. It is important to note that these are essentially the same municipalities that have benefited the most over the past 20 years. The present picture of this socioeconomic inequality is a result of three parallel developments: increasing, but regionally uneven penetration of small-scale PV, the growing spread between increasing retail electricity prices and decreasing feed-in tariffs, and simultaneously increasing self-consumption. Fig. 6 provides an intuitive impression that the EEG has a strong redistributive effect, leading to significant and persistent regional differences in the allocation of net regulatory benefits. In the following section, we substantiate this impression by calculating the corresponding Gini coefficients.

5.3. Inequality metrics

Fig. 7(a) depicts the evolution of the Gini coefficient for the installed small-scale PV capacities (in orange) and the Gini coefficient resulting from the distribution of the technical potentials (in green). The figure illustrates the already perceived significant inequality in the spatial distribution of small-scale PV. While the Gini coefficient of the spatial distribution of small-scale PV is 0.62 for the year 2000, today it is still significantly above 0 (2020: 0.42), expressing a significant and persistent structural inequality. This is all the more remarkable given that over the past 20 years, the number of small-scale PV units installed across the 401 municipalities has increased from less than ten thousand (2000) to 1.4 million (2021) by a factor greater than 100. Nevertheless, the inequality of the spatial distribution has structurally deepened rather than declined. In contrast, the Gini coefficient for the spatial



(a)

(b)

Fig. 7. Gini coefficients G of installed small-scale PV capacities, (a), and net prosumer benefits δ_i, (b), with frequency distribution over NUTS3 regions. Germany, 2000–2021. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

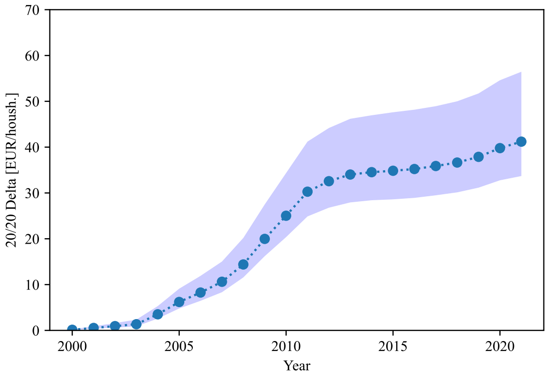


Fig. 8. Difference of annual net prosumer benefits δ between the top 20% of municipalities that benefit the most and the bottom 20% of municipalities that are burdened the most [EUR/househ.]. Germany, 2000–2021.

distribution of the technical potentials is much closer to 0 (0.17).[8] This Gini coefficient allows an indication of how large the inequality would be if the regional differences are solely due to the spatial distribution of the technical potentials. The delta of 0.25 between the Gini coefficients for the distribution of installed small-scale PV and the distribution of technical potential (the red colored area in Fig. 7(a)) is illustrative of the extent to which current regulation including the EEG has failed to incentivize spatially uniform deployment of small-scale PV.

Fig. 7(b) considers the associated financial perspective of resulting benefits, depicting the evolution of the Gini coefficient of the corresponding spatial distribution of the net prosumer benefits δ. The development of this Gini coefficient curve is parallel to the corresponding curve for the installed small-scale PV capacities.[9] In 2000, the Gini coefficient is 0.75 and falls slightly to 0.51 by 2012. In the following years until the present, however, there is only a marginal decline of the Gini coefficient to 0.49 in 2021 (the red colored area in Fig. 7(b)). This figure thus clearly shows that structural inequalities have also become manifest in the financial distribution of net prosumer benefits. Remarkably, feed-in tariffs and the margins they allow for PV investments have decreased significantly, especially since 2012, while socioeconomic inequality has practically not decreased. This, in turn, is a direct consequence of the simultaneous increase in self-consumption and the accompanying redistribution effect.

Table 1
Summary of central results (mean values).

Year	Δ [MEUR]	Δ [EUR/househ.]	Gini $G(\delta)$ [#]
2000	1	170	0.75
2005	60	532	0.64
2010	303	710	0.54
2015	446	573	0.51
2020	529	482	0.49

Taken only by itself, the Gini coefficient is an abstract and data-reducing quantity.[10] We therefore also evaluate the 20/20 delta; see Fig. 8. This figure shows the difference of annual net prosumer benefits δ between the top 20% of municipalities that benefit the most and the bottom 20% of municipalities that are burdened the most, in EUR/household. This difference has increased continuously over the past 20 years, from practically 0 EUR/household in 2000 to as much as almost 60 EUR/household (upper bound) in 2021. Moreover, it is important to keep in mind that here, again, we consider NUTS3 averages and not actual individual households.[11] Table 1 provides a brief summary of the central results of this study.

6. Conclusions and policy implications

Overall, this work demonstrates that the issue of cost-effectiveness to promote RES is closely linked to distributional issues, especially in the context of multiple scarcities in terms of financial resources, space, and acceptance. Space and acceptance partly constrain the realization of large-scale projects, whereas financial resources restrict the promotion of RES in general. All of this draws attention to the question of how to most efficiently promote small-scale PV to the required level. It is in this area that the paper aims to contribute.

6.1. Deficiencies of the current regulatory framework

This study identifies two main shortcomings of the current regulatory framework for small-scale PV promotion, which are closely related.

First, the current regulatory framework is partly inefficient with regard to the utilization of existing potentials. At present, large amounts of available small-scale PV potential are unused, with 106 NUTS3 regions (26%) below 3% potential exploitation, while only 52 NUTS3 regions (13%) have deployed more than 10% of their technical potential. It should be noted that not only does the electricity sector need to

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[8] The green line actually represents a (hardly noticeable) range of 0.16 – 0.17.

[9] In mathematical terms, the signs of the first derivatives are identical at all times.

[10] Different distributions can lead to the same Gini coefficients.

[11] The average of approximately 100 thousand households (approximately 80 million inhabitants, 2 inhabitants per household, and 401 NUTS3 regions result in an average of 100 thousand households per NUTS3 region).

Table A.1
Assumptions on the building structure.

			Detached	Semi-detached	Terraced	Other
A	$[\mathrm{m}^2]$	Lower bound	150	105	90	0
		Mean value	150	105	90	150
		Upper bound	150	105	90	300
F_{RT}	[#]	Lower bound	0.4	0.4	0.4	0.4
		Mean value	0.5	0.5	0.5	0.5
		Upper bound	0.5	0.5	0.5	0.5
ϕ	$[\mathrm{kW_p/m^2}]$	Lower bound	0.10	0.10	0.10	0.10
		Mean value	0.11	0.11	0.11	0.11
		Upper bound	0.13	0.13	0.13	0.13

Table A.2
Assumptions on $\overline{SCR}$, for the case of $FIT < \lambda$.

System size (x) $[\mathrm{kW_p}]$	$\overline{SCR}$ [#]
$0.0 < x \leq 1.5$	0.74
$1.5 \leq x \leq 2.5$	0.52
$2.5 < x \leq 3.5$	0.41
$3.5 < x \leq 4.5$	0.34
$4.5 < x \leq 5.5$	0.28
$5.5 < x \leq 6.5$	0.25
$6.5 < x \leq 7.5$	0.22
$7.5 < x \leq 8.5$	0.20
$8.5 < x \leq 9.5$	0.18
$9.5 < x \leq 10$	0.16

Table A.3
Assumptions on FLH. In [h/a].

Latitude (L)	FLH		
	Lower bound	Mean value	Upper bound
$47 \leq L < 48$	938	1000	1125
$48 \leq L < 49$	900	960	1080
$49 \leq L < 50$	863	920	1035
$50 \leq L < 51$	825	880	990
$51 \leq L < 53$	788	840	945
$53 \leq L < 55$	750	800	900

be fully decarbonized, but so do the heat and mobility sectors. A large part of this transformation will rely on electricity as a primary energy source. As such, there should be a great deal of political will to exploit the entirety of the existing potential. Rooftop PV may not be the least expensive form of clean energy, but it has the great advantage of largely avoiding land competition and being widely accepted.

Second, the current regulatory framework increases socioeconomic inequality, particularly by means of indirect cross-subsidization resulting from increasing self-consumption. Compared to households without PV, prosumer households can save approximately 40% of electricity costs on average, a large part of which is due to self-consumption. Part of this results in a direct cost transfer to the financial detriment of households without PV. This concerns the volumetric regulatory electricity price components, namely the EEG levy and network charges. In addition, tax revenues are reduced through self-consumption. At the same time, the significance of this self-consumption effect will continue to increase in the future. This is due to three effects occurring simultaneously. First, all newly installed PV systems are currently operated to maximize self-consumption because there is no longer a relevant positive margin effect. Second, older units (>20 years) that have previously been operated with feed-in logic are being phased out of the EEG subsidy (feed-in tariffs) and will continue to operate to maximize self-consumption. Third, the vast majority of all newly installed PV systems are equipped with stationary battery storage, which helps to increase the achievable self-consumption rates. In addition, new electricity based applications such as electric heat pumps and electric cars increase the ratios of achievable self-consumption in the future.

All of this further exacerbates the socioeconomic inequality that already exists today and ultimately jeopardizes the acceptance of the energy transition as such in the long term. The abolition of the EEG levy as of July 2022 by legislative resolution reduces this effect, but does not eliminate it in principle.

6.2. Guiding principles for a future regulatory framework

Based on the findings of this study, we identify three guiding principles of the future regulatory framework.

First, there must be transparency regarding the cost-benefit ratio and the socioeconomic distribution effect of regulatory instruments to promote small-scale PV. This is much needed for a quantitative evaluation of the efficiency of such instruments on the part of policymakers. This paper could provide a basis for such an assessment. The core idea is to systematically link existing but per se isolated data: namely, technical data such as installed PV capacities; socioeconomic data such as PV investment costs and feed-in tariffs; and operational model data such as self-consumption rates. Only in this way is it possible to obtain a complete picture of the impact of a policy instrument, including its indirect effects. In the case of small-scale PV promotion via feed-in tariffs, these indirect consequences particularly concern the redistributive effect through self-consumption.

Second, the direct effectiveness of regulatory instruments to promote small-scale PV should be increased. This begins with the specific design and adjustment of policy instruments to ensure that they have a direct effect, such as an actual incentive to feed electricity from small-scale PV into the public grid instead of cross-subsidization by avoiding third-party electricity purchases. This requires that the existing instruments are not considered in isolation, but rather in context. For example, a stronger involvement of prosumers to refinance grid costs can reduce the currently existing spread between feed-in tariffs and electricity prices and thus affect the operating model, e.g., the decision between feed-in and self-consumption. Moreover, direct effectiveness of policy instruments also concerns their local impact. That is, the promotion of RES must be more targeted and directed to where it is needed most. This is to avoid photovoltaics being concentrated in a few areas, while large parts of the landscape remain more or less unused for distributed PV.

Third, distributed PV should be smartly integrated into the overall system. This means that the regulatory framework must create incentives other than pure maximizing self-consumption, as is the case today. This last point is also intended to increase the integration of the electricity, heat and mobility sectors. Heat pumps and electric cars, when integrated into the system in large quantities, should be used as a system-serving source of flexibility, which requires a different incentive structure. This in turn means that adjustments to the regulatory framework in the electricity sector need be made in strategic coordination with the other sectors of the energy system.

6.3. Limitations and future work

We conclude by highlighting the limitations of this analysis and suggesting possible areas for future research.

First, electricity consumption is not spatially resolved in this analysis, but mean values per household are used; see Table A.4 for details. This leads to shifts in the calculation of the self-consumption for individual systems. However, since we consider aggregate values of the order of 100 thousand households per NUTS3 region, these cross-shifts should at least partially resolve statistically. Nevertheless, structurally induced differences are not reflected in this study. A more detailed spatial analysis of future research could take into account regionally different electricity consumption resulting from structural differences in the building stock.

Second, installed battery capacities are not spatially resolved in this study. Because in the past, existing battery storage systems were not

Table A.4
Model values for household demand, electricity prices, regulatory profits, costs, and battery storage ramp-up.

Year	D [kWh]	λ [ct/kWh]	FIT [ct/kWh]	c_{Inv}^{Batt} [EUR/kW$_p$]	c_{Inv}^{Stor} [EUR/kWh][a]	$\beta(t)$ [#]
2000	3512	14.92	50.62	6275	–	–
2001	3535	15.44	50.62	6120	–	–
2002	3557	16.08	48.10	5965	–	–
2003	3580	16.86	45.70	5810	–	–
2004	3602	17.51	57.40	5655	–	–
2005	3625	18.23	54.53	5500	–	–
2006	3614	18.91	51.80	5100	–	–
2007	3603	20.15	49.21	4700	–	–
2008	3593	21.43	46.75	4300	–	–
2009	3582	22.72	43.01	3900	–	–
2010	3571	23.42	36.34	3500	–	–
2011	3502	25.08	28.74	2500	–	–
2012	3433	25.76	20.09	2000	–	–
2013	3363	28.83	15.29	1900	2500	0
2014	3294	29.37	13.02	1800	2212	0.27
2015	3225	29.16	13.43	1750	1957	0.41
2016	3195	29.33	12.31	1650	1732	0.46
2017	3166	29.82	12.24	1600	1533	0.51
2018	3136	30.19	12.05	1550	1356	0.55
2019	3106	31.24	10.72	1500	1200	0.59
2020	3261	32.18	9.13	1450	1062	0.63
2021	3261	32.48	7.53	1400	940	0.67

[a] Referring to a 6 kWh battery storage.

required to be registered in the market master data registry; see Federal Network Agency (2022). Although registration is now mandatory, the data of the market master data registry is not yet complete due to the deadlines granted for subsequent registration. Therefore, this study takes a simplified top-down approach, considering the overall share of installed PV systems with battery storage. For this share of PV systems with batteries, flat assumptions are made for the resulting increase in self-consumption, see Section 3.2.1, without further spatial differentiation. The argument of at least partial statistical averaging at the NUTS3 level is valid in this case as well. Nevertheless, because the majority of new PV systems are installed in combination with battery storage, the spatial resolution of storage capacities is becoming increasingly important and a more detailed depiction remains open for future research.

Third, further limitations include the missing representation of regional differences in specific investment costs for PV and battery storage systems, again due to the lack of available data in the required quality, affecting the individual business case and thus the spatial analysis of benefits and costs. While component costs should have increasingly converged regionally as a result of world market prices, the costs of local craftsmen, in particular, still tend to be higher in the west of Germany than in the east of Germany (i.e., the former GDR).

Fourth, in this work, a regionally constant retail price is assumed to isolate the spatial variations induced by the EEG. This approach, however, should not diminish the importance of spatial variations in retail prices. For the country case of Germany, with per se non-locational pricing, differences in retail electricity prices are mainly driven by regionally different network charges and contribution margins. According to Federal Network Agency (2021), network charges are particularly high in parts of northern and eastern Germany. Therefore, in these areas, there should actually be a higher incentive for private households to invest in PV—but this is not reflected in the empirical data. Nevertheless, regionally varying retail electricity prices affect the spatial distribution of benefits and costs, as can be seen from Eqs. (3) and (4). In extreme cases, these variations in retail electricity prices can amount to up to 12 ct/kWh as a result of regional differences in network charges; see Federal Network Agency (2021). In 2020, network charges in the top 20% of municipalities benefiting most from the EEG differ only slightly from the bottom 20% of municipalities burdened most (7.0 ct/kWh versus. 7.1 ct/kWh), based on NUTS1 averages for the network charges (federal state averages). This indicates that the distribution structure according to Fig. 6 is not expected to change substantially even if spatial differences in network charges are taken into account. A deeper analysis of the interplay between geospatial variations in retail prices and the effects studied in this paper remains open for future research.

Fifth, future research could examine the effects of increasing sector integration in more detail. Widespread e-mobility and heat pumps as future standard heating technology alongside district heating could significantly increase the achievable self-consumption ratios and therefore further widen the gap between households with and without PV.

CRediT authorship contribution statement

Christoph Schick: Conceptualization, Methodology, Formal analysis, Software, Data curation, Validation, Visualization, Writing – original draft, Writing – review & editing. **Kai Hufendiek:** Supervision, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

Data will be made available on request.

Appendix

See Fig. A.1 and Tables A.1–A.4.

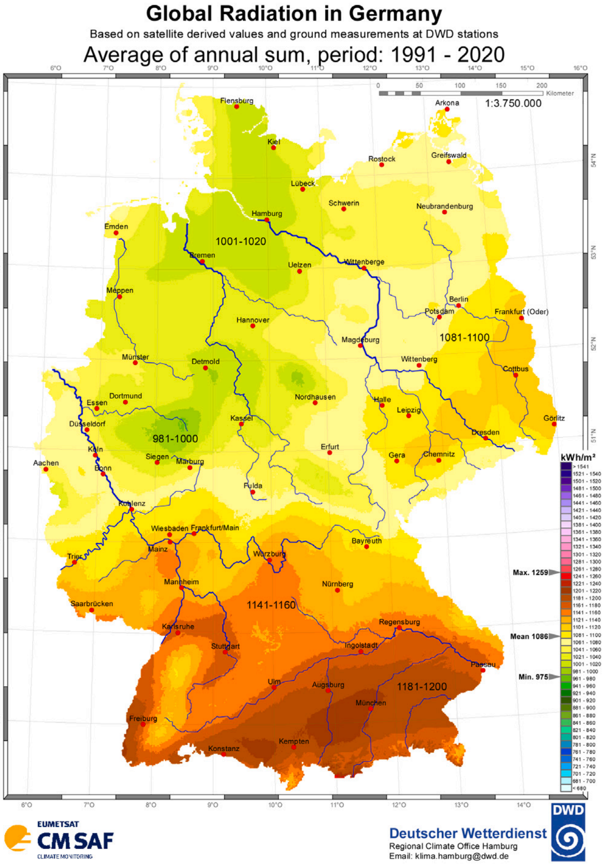

Fig. A.1. Global radiation in Germany; average of annual sum, period: 1991–2020. ©Deutscher Wetterdienst (DWD).
Source: Deutscher Wetterdienst (2022), retrieval date: 29.08.2022. The authors have obtained permission from DWD to use the figure in this paper.

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4 Paper B

4.1 Authors contribution

Table 4-0 shows the contributions of the co-authors of Paper B, based on the representative roles according to the Contributor Roles Taxonomy (CRediT).[11]

Tab. 4-0: Author contributions for Paper B: Role and impact of prosumers in a sector-integrated energy system with high renewable shares

	Paper B		
	Christoph Schick	Nikolai Klempp	Kai Hufendiek
Conceptualization	✓		
Methodology	✓		
Formal analysis	✓		
Software	✓		
Data curation	✓		
Validation	✓		
Visualization	✓		
Writing - original draft	✓		
Writing - review & editing	✓	✓	✓
Supervision			✓

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[11] See https://credit.niso.org/ for further details.

4.2 Role and impact of prosumers in a sector-integrated energy system with high renewable shares

IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. XX, NO. XX, XXX 2020 1

Role and impact of prosumers in a sector-integrated energy system with high renewable shares

Christoph Schick, Nikolai Klempp, and Kai Hufendiek

***Abstract*—Interactions between different policy instruments in real markets can lead to a mismatch between stakeholders striving for individual benefits and the attainment of an overall system optimum. These distortion effects are of particular relevance for sector-integrated systems with high prosumer shares. Distributed battery storage systems, in particular, could constitute a pivotal source of flexibility in close to 100% renewable energy systems. However, depending on their operation mode, these battery systems can either serve individual profit maximization or the benefit of the system as a whole. We quantify the resulting differences by means of a linear optimization model of the electricity market, which we stringently link to a stakeholder's complete cost-of-energy analysis including relevant regulatory price components. We demonstrate that the effects encompass both system cost changes and distributional effects for certain stakeholder groups. We quantify the effects and apply an impact variation analysis to demonstrate that they could be relevant in view of the overall acceptance of the energy system transformation.**

***Index Terms*—Distributed energies, flexibilities, prosumers, energy sector coupling, market framework**

NOMENCLATURE

Elements, sets, and indices

$pp_r; PP_r; n^r_{pp}$	Power plant class in region r; set of all power plant classes in region r; number of elements of this set.
PP_{el}	Set of electric power plants: GT (gas turbine); HYDRO (hydropower); PS (pump storage); BIO (biomass); W-ONS (onshore wind); W-OFFS (offshore wind); PV; and BS (battery storage).
$sto_r; STO_r; n^r_{sto}$	Storage class in region r; set of all storage classes in region r; number of elements of this set. $STO_r \subset PP_r$.
$r; R; n_r$	Model region; set of all model regions; number of elements of this set.
t; T; n_t	Momentary (discrete) model time (point); set of all possible model times; number of elements of this set. Throughout the model: $T = \{1, 2, ..., 8760\}$ and n_t = 8760.
n_{Pros} ($n_{NonPros}$)	Number of (non-)prosuming households.
$HS; HP$	Distributed heating technologies. HS = heat storage; HP = heat pump.
(v)RES	(Variable) renewable energy sources, including W-ONS; W-OFF; PV (all variable), and BIO (dispatchable).

Parameters

$c^l_{inv}(pp_r)$	Specific lifetime investment costs per power plant class pp_r in region r.
$c_{inv}(pp_r)$	Specific annualized investment costs, including fixed operation and maintenance costs per power plant class pp_r in region r.
$c_{prod}(pp_r, t)$	Specific costs of production per power plant class pp_r in region r and time t, including variable operation and maintenance costs, fuel costs, and CO_2 costs.
$c_{start}(pp_r, t)$	Specific start-up costs per power plant class pp_r in region r and time t.
$c_{sto}(sto_r, t)$	Specific charging costs per storage class sto_r in region r and time t.
$D_{el}(r, t); D_{th}(r, t)$	Electricity and residential heat demand in region r and time t.
$D_{el}(r); D_{th}(r)$	Annual electricity and residential heat demand in region r.
D^{total}_{el}	Total annual electricity demand of modeled system. $D^{total}_{el} = \sum_{r \in R, t \in T} D_{el}(r, t)$.
COP	Coefficient of performance of heat pump. Ratio of heating provided to electric work required.

Variables

$x_{inv}(pp_r)$	Number of investments per power plant class pp_r in region r.
$x_{prod}(pp_r, t)$	Produced power per power plant class pp_r in region r and time t.
$x_{start}(pp_r, t)$	Start-up power per power plant class pp_r in region r and time t.
$x_{sto}(sto_r, t)$	Charging power per storage class sto_r in region r and time t.
$x_{fill}(pp_r, t)$	Fill level per storage class sto_r in region r and time t.
$x_{trans}(r, r', t)$	Electricity transmission between regions r and r' and time t.
$\lambda^*(r, t)$	Dual (shadow) variable of the load coverage restriction at minimum system cost (indicated by the asterisk), which can be interpreted as the wholesale market price.

I. INTRODUCTION

TO achieve global climate goals, the CO_2 emissions of our energy system need to be close to zero by 2050, encompassing not only the electricity sector, but also all other sectors (heating and transport). Increased adoption of distributed energy sources could make a significant contribution to the decarbonization of the energy system. This process involves numerous stakeholders, some of whom are active market participants, referred to as (energy) prosumers; see [1], for instance.[1] The following considerations should therefore be

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[1] Here and in the following the term stakeholder refers specifically to prosuming and non-prosuming households.

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included in the analysis of 100% renewable energy systems:

1) When a large number of prosumers is involved, a power market analysis should consider stakeholder perspectives, behavior, and strategic acting.
2) Energy systems have mainly been studied at a wholesale market level, whereas prosumer decision-making takes place in the retail market. The regulatory market framework should therefore be considered as important link between these markets.
3) Sector integration could increase the complexity of aspect 2 above, as it couples potentially incoherent regulatory frameworks from different sectors (e.g., electricity sector and residential heating sector in case of heat pumps; see [2] for details on technical modeling issues).

Examples of the aspects mentioned above are the non-system optimal operating modes of distributed battery storages in order to increase self-consumption (SC) and minimize the purchase of expensive electricity from the grid. This is an example of inefficient behaviour as consequence of a market price signal which is distorted by regulatory price components. The goal of this study is to quantify such distortion effects by means of a stringent and comprehensive assessment of both the system and stakeholder perspectives. We quantify and compare the total system cost and cost distribution to household energy consumers for a) when prosumers act to maximize their own profit and b) when prosumers act to maximize for the benefit of the system.

In a 100% renewably energy sources (RES) system, the role of storage is central as it constitutes a source of flexibility to balance volatile renewable production. Studies such as [3][2] demonstrate that the penetration ratio of distributed flexibility options provided by household battery storage systems is growing, driven by both intrinsic and extrinsic motivations; see [4]. An efficient energy system should guarantee that the distributed flexibilities are operated such that the maximization of individual benefits coincides with the optimization of the overall system. All effects presented in this work should, in principle, also occur for lower RES shares and prosumer penetration ratios. However, we demonstrate that the *order of magnitude* of the effects at both system and stakeholder levels is strongly correlated with the number of prosumers. This number, in turn, is most likely the highest for maximum overall RES shares. Our analysis is consequently of particular relevance for energy systems getting close to 100% RES. After all, this transition is not only a question of the necessary technologies, but also of the required market design. The motivation of our study is therefore to reveal challenges that current market designs face when dealing with prosumers.

A. Related works

1) Analyses of strategic prosumer behavior

Numerous studies focus on selected aspects of strategic prosumer behavior and its impact on the energy market - in many cases from a local perspective. [5] investigate the economic merit of cloud energy storage for prosumers from virtual aggregation of a small number of decentralized battery capacities. Analyzing the effects of different grid-use and feed-in tariffs (FiTs), the authors find that making use of cloud storage can be economically beneficial. However, the implemented operating strategy for the cloud storage primarily aims at maximizing SC; overall network or wholesale market effects are not in the focus of the analysis. The economic advantage of SC maximization is further analyzed by [6]. However, this study focusses only on the prosumer benefit, either at the household or community level, but does not consider the overall energy system perspective. Furthermore, the authors of [7] discuss that operating combined PV and battery systems to maximize SC is not energy system optimal but rather a consequence of a regulatorily distorted market signal. They suggest the introduction of a market alignment factor that measures the short-term welfare contribution of the prosumer battery, and they apply this to alternative market designs, including time-varying FiTs. However, they take the wholesale prices as exogenous time series, whereas in our analysis it is a model-endogenous output. A different research focus for prosumer demand response is provided by the authors of [8], who discuss alternative options to incentivize price-responsive demand in view of customer baselining. They demonstrate that recompensing the full locational marginal price could result in double-payment incentives. This paper is relevant for us in that it explicitly considers the connection between the wholesale and retail markets, as we also do, but with a different focus. In addition to the analysis of single household prosumers, other studies consider the aggregators of demand response (e.g., [9]) and distributed generation. [10], for instance, demonstrate the potential market power of such aggregators via strategic curtailment to manipulate prices. Another approach is to consider virtual prosumer associations (VAs) [11], which differ from traditional aggregators in that they are non-profit-seeking entities. On the basis of a split market setting, with a traditional energy market on the one hand and a separate RES market on the other, these VAs enable prosumers to sell their energy at average total costs rather than at close to zero marginal costs. Therefore, VAs constitute an alternative to FiTs, which our analysis is based on, in order to internalize RES' positive externalities. In addition, in view of sector integration, a range of studies consider further flexible applications such as heat pumps, heat storages, and electric vehicles (EVs). [12] demonstrate the capability of virtual aggregation of multiple households with electric and thermal flexibilities as well as EVs to follow a given dispatch pattern. However, this analysis does not contain the flexible interaction between prosumers and the power market.

2) Regulatory framework analyses

A number of studies demonstrate the impact of the regulatory framework on both the prosumer value proposition and non-prosuming households. An overview of different regulatory schemes for prosumer SC in 24 countries is provided by [13]. FiTs and net-metering schemes in combination with SC to save grid electricity costs are widely spread. [14] analyze prosumer perspectives for the country cases of Italy and Spain and demonstrate that significant economic differences exist depending on the regulatory country-specific framework.

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[2] For the German market.

Moreover, [15] focus specifically on the interplay between prosumer business models, the recovery of utility system costs, and cost distribution among end-customers under different rate designs. For the case of California, [16] demonstrate that wealthier households in particular benefit from the regulatory incentives for residential PV adoption such as direct subsidies, renewable energy credits, and tax breaks. In this context, they also mention the term ”death spiral”, which refers to a situation when fixed costs are allocated to fewer and fewer customers, resulting in ever higher prices for the remaining customers. Furthermore, [17] discuss the impact of prosumers on network cost recovery in depth and how volumetric network charges provide indirect incentives (i.e., cross subsidies) for prosumers to maximize SC. This simultaneously results in inequality issues and higher charges for non-prosumers. All of these analyses provide valuable insights into the effects of the regulatory electricity rate design on cross subsidization and related distributional aspects; however, they are not connected to a fundamental system analysis; that is, they do not answer what ratios of SC could, in principle, be system-compatible and by how much system costs increase for higher self-consumption ratios (SCRs).

3) System model analyses

A third class of studies relate to power market and techno-economic models of the electricity system as a whole in the presence of prosumers. A mainly qualitative discussion of how prosumers can be integrated into the energy system is provided by [18], who present three alternative prosumer market models. Furthermore, [19] perform an analysis of the total system cost increase through distributed PV and battery systems when operated to maximize SC rather than operated in a system-oriented manner. As we do, the authors use a linear optimization model of the electricity market. However, they do not break down the system cost increase in detail, nor do they consider distributional end-customer aspects, including retail prices. [20] analyze a framework for the aggregation of demand response instruments, including distributed generation and storage in the day-ahead electricity market. However, our perspective differs in that in our analysis, we do not aim at aggregators' profit maximization but total system cost minimization. [21] model the interaction of strategically acting prosumers with other entities of the power market. The authors demonstrate prosumers' principle capability of exercising market power, although they would benefit generally more by acting as price takers. A main difference to our analysis is the underlying market scheme: The authors base their analysis on locational marginal prices, whereas in our case, the distributional effects result precisely from the fact that a ”predetermined breaking point” exists between wholesale price and (ex-post) volumetric network charges (as well as RES support costs). Moreover, energy storage systems, which are a key part of our model, are not considered.

B. The proposed contribution

From the review of literature, we conclude that in many countries, electricity rate designs encompass regulatory components (e.g., FiTs, direct subsidies, RES credits, tax breaks, and levies exemptions). One can interpret at least some of these components as different methods to internalize RES' positive externalities, [11], [22]. As such, most of these policy instruments are characterized by the fact that they are, at least to some extent, decoupled from the wholesale market. This has an impact both on the energy system as a whole and on individual stakeholders in particular. The novelty value of this paper lies in quantifying these effects in a closed model, explicitly considering both wholesale and retail markets. The following leading questions drive our analysis:

- **System:** What SCRs are, in principle, system-compatible? What happens from a system perspective when prosumers strive for higher SCRs? What is the difference between price-reactive and static operation of distributed flexibilities?
- **Stakeholder:** By how much do stakeholder retail costs change when prosumers strive for high SCRs?

A further aspect is that we combine the electricity and residential heating sector in our analysis. This is motivated by three main reasons. First, in our study, we consider the complete costs of energy at the stakeholder level, as they are of ultimate relevance for both prosumers and non-prosumers. These costs encompass electricity and heating. In view of mobility, transporting could also, in principle, be included. However, in contrast to electricity and heating, vehicles are not a commodity; therefore, they are not considered in this paper. Second, heat pumps and heat storage systems are dispatchable elements, which add further flexibility to the energy system and can thus increase the prosumer impact. Third, beyond the scope of this paper and left open for a separate analysis is that the electricity and heating sectors are usually treated differently and thus inconsistently in terms of regulation. This means that their interplay can lead to further distortion effects.

II. METHODS

A. General modeling approach

The basic idea of our research approach is to fully interlink a bottom-up market model (system perspective) with a full cost of energy ($FCOE$) analysis (stakeholder perspective) in an energy system with integrated electricity and residential heating sectors and high shares of both RES and prosuming households. For the assessment at the stakeholder level, we explicitly consider relevant regulatory price components that are consistently derived from the system analysis. For this purpose, we reduce the total system cost $C_{sys}^{total}(\cdot)$, which is a function of n parameters (see Eq. 3) to a function of one single (implicit) parameter b. This parameter represents a behavioral constraint given by the prosumer SC (i.e., the amount of produced energy from prosumer PV that the prosumers can consume themselves). To guarantee stability of results[3], we minimize the total system cost and analyze the functional dependency of the minimum total system cost $C_{sys}^{total,*}(b)$. Under consideration of a particular regulatory market framework, we then also derive the prosumer and non-prosumer

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[3] In the sense that the market clears at minimal total system cost with the dual variable of the load coverage restriction being the equilibrium price.

$FCOE(b)$. By analyzing only the changes of $C_{sys}^{total,*}(b)$ and $FCOE(b)$ with b, we aim to reduce the impact of arbitrary model configurations (parametric uncertainties) as much as possible; see Fig. 1. The prosumer technologies included in our analysis are limited to PV, electric and thermal storages, and heat pumps.

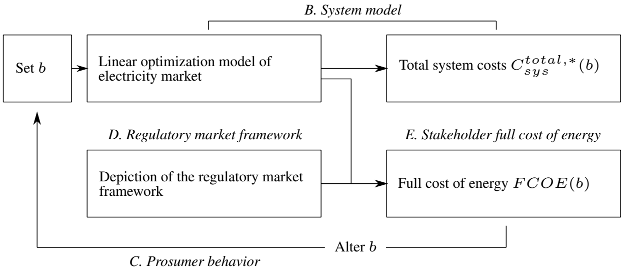

Fig. 1. Flow chart of the analysis.

B. System model

For the analysis at the system level, we use a linear optimization model of the electricity market, namely the *European Electricity Market Model, E2M2*, which minimizes the annual total system cost C_{sys}^{total} under perfect foresight and hourly temporal resolution (i.e., 8760 hours); see [23] and [24].

$$\min_{x\in\mathbb{R}_+^n} C_{sys}^{total} = \min_{x\in\mathbb{R}_+^n} (c^T x + C_{grid}^{total}) = \min_{x\in\mathbb{R}_+^n} c^T x \quad (1)$$

In our analysis, total grid infrastructure costs C_{grid}^{total} are considered as a constant offset value, not being part of the optimization algorithm. Furthermore, $c(\cdot)$ and $x(\cdot)$ are vectors $\in \mathbb{R}_+^n$ depending on time, region, technology (power plant) class and cost type, as specified in the following.

$$\begin{aligned} x &= (x_{inv}, x_{prod}, x_{start}, x_{sto}, x_{fill}, x_{trans}) \in \mathbb{R}_+^n \\ c &= (c_{inv}, c_{prod}, c_{start}, c_{sto}, 0, ..., 0) \in \mathbb{R}_+^n \end{aligned} \quad (2)$$

The cost vector includes investment costs; variable production costs (operation and maintenance costs, fuel costs, and CO_2 costs); start-up costs; and variable storage costs; for further details, see Appendix A. $x(\cdot)$ contains the corresponding decision variables. The dimension n of the vector space for the decision variable x is given by

$$n = \sum_{r\in R} \left(n_{pp}^r \cdot (1+2n_t) + 2n_{sto}^r \cdot n_t\right) + \sum_{\substack{r_1,r_2\in R \\ r_1\neq r_2}} n_t \quad (3)$$

Prosuming and non-prosuming households are represented as different model regions, each of which has electricity and heating demands that can be covered both by local generation within these regions or through (bi-directional) electricity transmission with a central region; see Fig. 2. Note that a model region is not identical to a physical region, i.e., there is no restriction for x_{trans}, but is rather a container of elements with the same properties (e.g., distributed prosumer technologies, non-prosumer technologies, and central power plants). Although this construction is an obvious abstraction, it enables us to control the SC of the prosumer region on the one hand, and to attribute costs to end-consumers on the other hand.

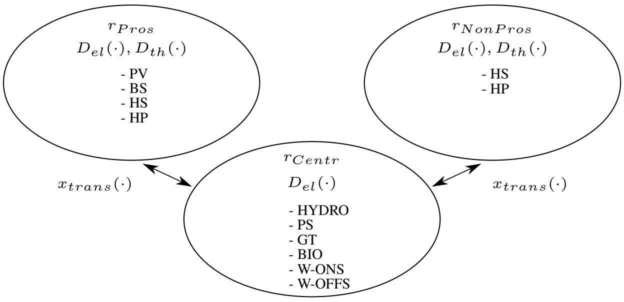

Fig. 2. Depiction of the system model scheme with regions r_{Pros} (prosumer region), $r_{NonPros}$ (non-prosumer region), and r_{Centr} (central region).

Next, we list the relevant model restrictions. For further details, see Appendix B.

Static system adequacy restriction:

$$\sum_{\substack{r\in R \\ pp_r\in PP_{el}}} x_{inv}(pp_r)\cdot Credit(pp_r) = \sum_{r\in R} \max_{t\in T}\{D_{el}(r,t)\} \quad (4)$$

This restriction forces the model to invest in (dispatchable) electric power plant capacities, such that the sum of these capacities, weighted by their operational reliabilities, matches the maximum electric load in the model year. $Credit \in \{0,1\}$ represents the corresponding reliability factors, which are zero for variable RES (vRES).

Investment restrictions: In addition, RES investments and the central pump storage are restricted by a given capacity I per power plant class.

$$\begin{gathered} x_{inv}(pp_r) = I(pp_r) \\ \forall pp_r \in PP_{RES} \cup \{PS\}, r \in R \end{gathered} \quad (5)$$

The rationale behind this constraint is that we can alter b without changing the central power plant structure in the different model runs. In this way, the increase in total system cost is caused entirely by the prosumer behavior, i.e., the investment and unit commitment decisions of the decentralized prosumer technologies (BS, HS, and HP).

Demand coverage restrictions: Regional demand must be covered by production including electricity transmission between regions.

Electric demand:

$$\begin{aligned} x_{prod}(pp_r,t) = &\underbrace{D_{el}(r,t) - P_{vRES}(pp_r,t)}_{\text{residual load}} + x_{sto}(pp_r,t) \\ &+ \sum_{\substack{r'\,in\,R \\ r'\neq r}} \underbrace{(x_{trans}(r,r',t) - x_{trans}(r',r,t))}_{\text{electricity transmission between regions}} \\ &+ \underbrace{\frac{x_{prod}(HP_r,t)}{COP(t)}}_{\text{electricity demand for heat pump}} \\ &\forall pp_r \in PP_{el}, r \in R, t \in T \end{aligned} \tag{6}$$

Under the premise of a market with complete competition and marginal-cost-based pricing, the dual variable of the electric load coverage restriction can be interpreted as the electricity price at the wholesale market $\lambda^*(r,t)$. It is per se a function of both the time and the region. However, as no transmission capacity constraints apply to our model, $\lambda^*(r,t) = \lambda^*(t)$. Note that the vRES production P_{vRES} explicitly allows curtailment at no charge. A further note is that our model has hourly temporal resolution. For reasons of clarity, we therefore omit the multiplication of x_{prod}, which has the physical dimension of power [MW], by the time step length (1 [h]). In our model, we only consider residential heat being supplied by heat pumps, which are the links between the electricity and heating sectors.

Heat demand:

$$\begin{aligned} x_{prod}(pp_r,t) = D_{th}(r,t) + x_{sto}(HS_r,t) \\ \forall pp_r \in \{HS, HP\}, r \in R, t \in T \end{aligned} \tag{7}$$

Storage restrictions: These restrictions reflect the logic of both the battery and the heat storage. The fill level changes between two consecutive time points by the amount of charged or discharged energy within this time. Moreover, note that the model requires equal fill levels at the beginning and at the end of the modeling period. Although battery degradation can considerably impact the optimal storage operation, see [25], for instance, we do not consider it directly. However, degradation is indirectly taken into account in view of the comparatively short battery lifetime; see Section III. Moreover, we neglect further potential storage inefficiencies. This is a simplification; however, it is made in every model run and we consider only deltas of model runs instead of absolute model run values. Both battery and heat storages are characterized by their maximum storage content as well as their charging and discharging (power) capacities.

$$\begin{aligned} x_{fill}(sto_r,t') &= x_{fill}(sto_r,t) + x_{sto}(sto_r,t) - x_{prod}(sto_r,t) \\ x_{sto}(sto_r,t) &\leq x_{inv}(sto_r) \cdot \frac{MaxCharging(sto_r)}{MaxPower(sto_r)} \\ x_{prod}(sto_r,t) &\leq x_{inv}(sto_r) \\ x_{fill}(sto_r,t) &\leq x_{inv}(sto_r) \cdot \frac{MaxContent(sto_r)}{MaxPower(sto_r)} \\ &\forall sto_r \in STO, r \in R \text{ and } t,t' \in T, t'-t = 1 \end{aligned} \tag{8}$$

Prosumer self-consumption restriction: The prosumer SC is defined as the annual amount of energy that is produced by prosumer PV power and battery storage systems - under consideration of curtailment - less the amount of energy that is fed into the public grid. This restriction guarantees that the prosumer SCR equals the model parameter b. In fact, our modeling approach is to leave all parameters unchanged, with the exception of b. In this way, $C^{total}_{sys}(\cdot)$ is entirely reduced to $C^{total,*}_{sys}(b)$.

$$\begin{aligned} &SCR = b \quad \text{with} \quad SCR = \frac{SC}{\sum_{t\in T} P_{PV}(t)} \\ &\text{and} \\ &SC \equiv \sum_{t\in T} \underbrace{P_{PV}(t) + x_{prod}(BS,t) - x_{sto}(BS,t) - FI(t)}_{\equiv sc(t)\text{: as expressed from a production perspective}} \\ &\quad = \sum_{t\in T} \underbrace{D_{el}(r_{Pros},t) + \frac{x_{prod}(HP_{Pros},t)}{COP(t)} - GS(t)}_{\equiv sc(t)\text{: as expressed from a demand perspective}} \\ &\text{and} \\ &FI(t) = x_{trans}(r_{Pros}, r_{Centr}, t) \\ &GS(t) = x_{trans}(r_{Centr}, r_{Pros}, t) \end{aligned} \tag{9}$$

Eq. 6 was used for the equivalence of the two formulations for SC in lines 2 and 3 of Eq. 9. $FI(t)$ stands for the surplus energy fed into the public grid, and $GS(t)$ stands for the electricity supply from the grid. The general idea is to vary the SCR bound b and to study the resulting system and stakeholder effects.

To summarize: First, we set all model parameters including b. Then, a linear optimization of the electricity market is conducted to find a system cost optimal solution which is determined by a) the size of decentral investment options (i.e., storage and heat pump) and b) the actual unit commitment of all power plants in the model. Finally, we alter b and start all over again.

C. Prosumer behavior

For the analysis, we analyze three different cases of distributed flexibility operation, which are representative of prosumers' different behaviors and market integrations. The core idea is to reduce prosumer behavior in our model to one single parameter, their $SCR = b$. On the one hand, this approach offers the benefit of being able to apply a closed system model. In addition, this approach is based on observable prosumer behavior in reality, which oftentimes aims at maximizing SC; see [13], for instance. On the other hand, we note that our approach is limited in that we do not use a separate objective function for prosumers.

Case 0 - full market integration - the reference line:

$$SCR \geq 0$$

This basically leaves the SCR fully unrestricted. This setup represents a market model of full prosumer integration (i.e.,

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prosumers operate their dispatchable resources according to the market signal without further restrictions).[4]

Case 1 - market integration under restrictions - fixed annual self-consumption:

$$SCR = b, \qquad b > 0$$

This case represents a setting in which prosumers are guaranteed to achieve a certain SCR, but still react to the market signal as long as $SCR = b$ remains guaranteed. This case is key to our analysis because it represents a lower limit for system cost increases at high SCR (i.e., the minimum increase possible that cannot be undercut regardless of the prosumer behavior).

Case 2 - fully inflexible charging patterns - the chronological charging: This case is represented by

$$sc(t) = b(t), \qquad \forall t \in T$$

In such a case, the unit commitment of the distributed flexibilities is completely predetermined by a prosumer heuristic. That is, the operations of storage and the heat pump are model-exogenously fixed in advance, which represents a complete decoupling from the wholesale market. For our analysis, we analyze a particular strategy that we refer to as *chronological charging*; see [26]. The general idea of this heuristic is to consume, whenever possible, self-generated energy either directly, or to store it for later consumption. It can be shown that this strategy ensures maximum SC.[5]

For $P_{PV}^{Pros}(t) > 0$:

1) Self-consume electricity directly.
2) Store surplus PV electricity into battery storage.
3) Use surplus PV electricity to operate heat pump for direct coverage of heat load.
4) Use surplus electricity to operate heat pump and turn transferred heat into heat storage.

Reading logic: Try 1); if this not possible, then try 2), ...

For $P_{PV}^{Pros}(t) = 0$:

1) Discharge battery storage to cover as much electricity demand as possible.
2) Discharge battery storage to operate heat pump to cover as much heat demand as possible.
3) Discharge heat storage to cover as much heat demand as possible.

D. Regulatory market framework

So far, we have explained how to calculate the total system cost in our model representing the wholesale market. Next, we allocate these costs to end-customers in the retail market with regulatory price components. The wholesale market results in a market clearing price usually based on marginal costs, whereas in the retail market, end-customers are predominantly charged fixed retail rates. This is partly a consequence of time-averaging rate designs including distributor fixed costs, which lead to retail prices reflecting monthly or annual average costs of service rather than real-time prices [8].

Another source of retail prices deviating from wholesale prices is the recovery of fixed costs on the basis of the regulatory framework. Market designs across countries deal with the recovery of fixed costs differently. While capacity markets directly address the recovery of fixed costs of generation, energy-only markets tend to recover fixed costs at least partly through high scarcity prices in few periods of time [27]. To recover the fixed costs of network infrastructure and operation, either locational marginal pricing or separate network charges can be applied [28]. While the former produces locational electricity prices, which (at least partly) reflect the costs of transmission, the latter is applied especially for markets with non-locational prices. In this case, the total network costs are oftentimes distributed to the end-customers through charges on electric energy withdrawn from the grid (volumetric network charges). In turn, these network charges burden retail prices, particularly when allocated to fewer end-customers (see [15], for instance), while prosumers can avoid these charges through SC. Note however, that there are also alternative allocation mechanisms, e.g., by (peak load) capacity.

Furthermore, levies, subsidies, and related policy interventions constitute additional sources of wholesale market distortion. FiTs have been introduced in many countries; these tariffs guarantee distributed RES owners fixed rates for electricity fed into the public grid. Comparable to volumetric network charges, the sum of overall incurred FiTs, in turn, can be allocated to end-customers via volumetric RES support costs.

In this paper, we consider a retail market with non-locational prices, volumetric network charges CA_{grid}, FiTs for vRES support, and volumetric vRES support costs CA_{vRES}. This is motivated by the German market framework, where volumetric network charges and RES support costs[6] have constituted the two single major regulatory price components of the retail electricity price in recent years; see [29].

The regulatory market frameworks vary significantly in different countries. For our analysis, to produce quantitative results, we assume a particular framework with specific features and simplifications. Even though these specific features may not apply to every country, our results are transferable to other regulatory frameworks. That is, the observed effects will basically always occur under two prerequisites: A retail market which deviates from the wholesale market and the presence of dispatchable prosumer technologies such as storage or heat pumps.

E. Stakeholder full cost of energy

In this Section, we explain how we calculate the $FCOE$ by connecting quantities from the system analysis to corresponding end-customer cost components in the retail market; see Fig. 3.

---

[4] To be precise, this setting resembles a market with complete competition, which, according to the first fundamental welfare theorem, would tend toward a competitive, weakly Pareto-optimal equilibrium.

[5] Besides, for the case of both electrical and thermal flexibilities, small deviations from the theoretical optimum through explicitly fixing the order of technology operation.

[6] *German Renewable Energy Sources Act* (*EEG*).

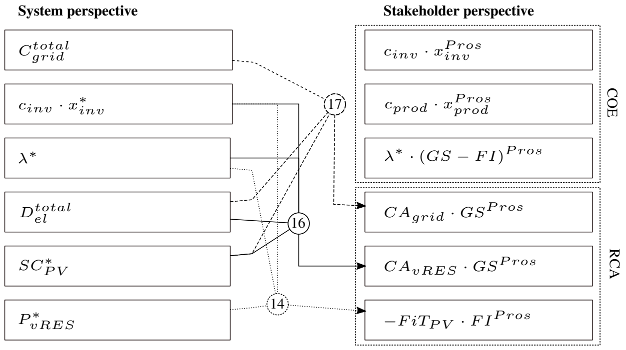

Fig. 3. Depiction of the link between system parameters and stakeholder $FCOE$. Numbers in circles refer to corresponding equations.

The $FCOE$ is the sum of the market-based cost of energy COE and regulatory cost components, denoted by RCA.

$$FCOE(b) = COE(b) + RCA(b) \tag{10}$$

The COE is the sum of the levelized cost of energy (LCOE [storage, LCOS]) multiplied by the energy generated (storaged) plus the costs (profits) of electricity withdrawn from (fed into) the distribution grid.

$$\begin{aligned} COE(b) = & \underbrace{c_{inv} \cdot x_{inv}^{Pros} + c_{prod} \cdot x_{prod}^{Pros} + +c_{sto} \cdot x_{sto}^{Pros}}_{\text{LCOE (LCOS) times energy generated (storaged)}} \\ & + \underbrace{\sum_{t \in T} \lambda^{*}(t) \cdot (GS^{Pros}(t) - FI^{Pros}(t))}_{\text{wholesale cost / profit for energy supplied from / fed into grid}} \end{aligned} \tag{11}$$

In Eq. 11 and all following equations, all variables with a superscript index $(...)^{Pros}$ denote the proportion of the corresponding decision variable of the overall system solution that is attributable to a single prosumer household. Note that the same applies to non-prosuming households, which are denoted by the superscript index $(...)^{NonPros}$. For the sake of clarity, we will only include the $Pros$ index in all the following equations. System variables with an asterisk index $(...)^{*}$ denote system optimality at $SCR = b$.

$$n_{Pros} \cdot (...)_{...}^{Pros} = (...)_{...}^{*} \quad \text{at} \quad SCR = b \tag{12}$$

The regulatory price components encompass the cost allocation for the grid and vRES, as well as FiR in the prosumer case.

$$\begin{aligned} RCA(b) = & \sum_{t \in T} (CA_{grid} + CA_{vRES}) \cdot GS^{Pros}(t) \\ & - \sum_{t \in T} FiT_{PV} \cdot FI^{Pros}(t) \end{aligned} \tag{13}$$

Note that here, we applied the fact that the total amounts of charged and discharged energies from the storages cancel within the one-year model time period. Under perfect foresight, an ideal FiT_{PV} would precisely compensate for the difference between annualized prosumer investment costs for PV and its annual profit, which is generated in the wholesale market. Moreover, in an efficient market, the total amount of prosumer PV production should be fully available on the market. This means that the prosumer should be compensated with FiT_{PV} for the total amount of its PV production P_{PV}^{Pros} - regardless of the physical flow of electricity, which involves direct balancing of local demand and production. All considerations apply for all other vRES as well; hence

$$FiT_j = \frac{c_{inv}(j) \cdot x_{inv}^{*}(j) - \sum_{t \in T} P_j^{*}(t) \cdot \lambda^{*}(t)}{\sum_{t \in T} P_j^{*}(t)} \quad \forall j \in vRES \tag{14}$$

Consequently, CA_{vRES} result from allocating the absolute amount of RES support costs, i.e., the numerator of Eq. 15, to the end-customers per energy withdrawn from the grid, i.e., the denominator of Eg. 15.[7] In other words, CA_{vRES} are the specific (volumetric) RES support costs that result from paying FiTs to the prosumers.

$$CA_{vRES} = \frac{\sum_{j \in vRES} FiT_j \cdot \sum_{t \in T} FI_j^{*}(t)}{\hat{D}_{el}^{total} - \sum_{j \in vRES} \sum_{t \in T} sc_j^{*}(t)} \tag{15}$$

Next, we assume that $sc_j^{*}(t) = 0$ for all vRES except PV. As a result, $FI_j^{*}(t) = P_j^{*}(t)$ for all vRES except PV. Using Eq. 14, this leads to

$$\begin{aligned} CA_{vRES} = & \sum_{\substack{j \in vRES \\ j \neq PV}} \frac{c_{inv}(j) \cdot x_{inv}^{*}(j) - \sum_{t \in T} P_j^{*}(t) \cdot \lambda^{*}(t)}{\hat{D}_{el}^{total} - SC_{PV}^{*}} \\ & + FiT_{PV} \cdot \frac{(P_{PV}^{*} - SC_{PV}^{*})}{\hat{D}_{el}^{total} - SC_{PV}^{*}} \end{aligned} \tag{16}$$

Analogous considerations lead to the derivation of the cost allocation for grid, CA_{grid}.

$$CA_{grid} = \frac{C_{grid}^{total}}{\hat{D}_{el}^{total} - SC_{PV}^{*}} \tag{17}$$

III. CENTRAL MODEL ASSUMPTIONS

Assumptions for installed RES capacities are loosely based on 2050 values of the 95% decarbonization scenario of [30]; see Table I. Specific investment cost values are mainly based on the 2050 assumptions of [31].

Note that we have assumed all PV to be with the prosumers, neglecting further ground-mounted PV in the central system. In Section V, however, we perform an impact variation analysis where a certain share of the 120 GW PV is shifted from the prosumer region into the central model region. Furthermore, 20 GW of pump storage capacity representing the central system flexibility is assumed.[8] Annuity factors are calculated on the

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[7] To be precise, $\hat{D}_{el}^{total}$ denotes the total annual electricity demand less the energy volume which is exempt from the allocation mechanism. For this study, we have assumed an exemption of 150 TWh.

[8] This parameter will be varied in Section V as well.

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TABLE I
ASSUMPTIONS ON CAPACITIES AND SPECIFIC INVESTMENT COSTS, 2050

PP	c^l_{inv} EUR/kW	c_{inv} EUR/kW	x_{inv} GW	C^{total}_{inv} MEUR	**Source**
BIO	1,000[a]	165	35	5,777	[30], [31], [b]
W-ONS	1,295	125	100	12,488	[30], [31], [b]
W-OFFS	2,350	245	60	14,684	[30], [31], [b]
PV (Pros)	450	42	120	5,031	[30], [31], [b]
BS (Pros)	230	26	*Model output*		[30], [31], [b]
HS	100	8	*Model output*		[30], [31], [b]
HP	720	118	*Model output*		[30], [31], [b]

[a] Cost pro rata for electricity (cogeneration of heat and power).

[b] Kopernikus project Energiewende navigation system (ENavi).

TABLE II
ASSUMPTIONS ON DEMANDS, 2050

R	n m	D_{el} TWh	D_{th} TWh
r_{Pros}	20	80	200
$r_{NonPros}$	15	60	150
r_{centr}	n/a	360	0

basis of a 5% interest rate and lifetimes of 14 years for BS; 25 years for PV, HP, W-ONS, and W-OFF; and 30 years for BIO, and HS. Moreover, CO_2 prices of 150 EUR/t for the electricity sector are taken as a basis, which seems compatible with other studies, such as [30].[9] For further details, including variable production costs, see Appendix A. As a plausibility check, Appendix C shows the invested battery and heat storage contents (model outputs), which are within reasonable ranges. Figures for the electricity and heat demands, and numbers of households are loosely informed by the German market size; see Table II. Moreover, representative synthetic load profiles (so-called "H0 profiles") are applied for the electricity demands of the prosuming and non-prosuming households; see [32]. The heat demand profiles are calculated on the basis of [33] for heat networks of the region Mannheim. vRES profiles are based on historical data for Germany and the reference year 2006, as in [24]. Throughout the study we assume that heat pumps operate at a COP of 3.

IV. RESULTS

A. Reference line setting

For the reference line setting, we evaluate *Case 0 - full market integration.*

In this setting, the system optimum coincides with the sum of individual prosumer optima (i.e., no market distortion effects are present). The system cost base is 88,300 MEUR/a with total CO_2 emissions amounting to 11.4 million tons, equivalent to a 97% reduction in CO_2 emissions compared to 1990[10]. Fig. 4 depicts the annual electricity production by technology type. Total electricity production is 625 TWh, of which about 125 TWh is electricity for heat. This system is both highly sector-integrated and dominated by vRES production. Due to the large capacities of installed vRES, free curtailment occurs to a large extent (24% W-OFFS, 30% W-ONS, and 15% PV).[11] Compared to other studies, such as [30], BIO production is high. This should be seen in the context of the restriction to relatively few considered technologies. In fact, BIO is representative of all kinds of dispatchable RES in this system and could either be replaced by synthetic fuel or hydrogen imported, as well.

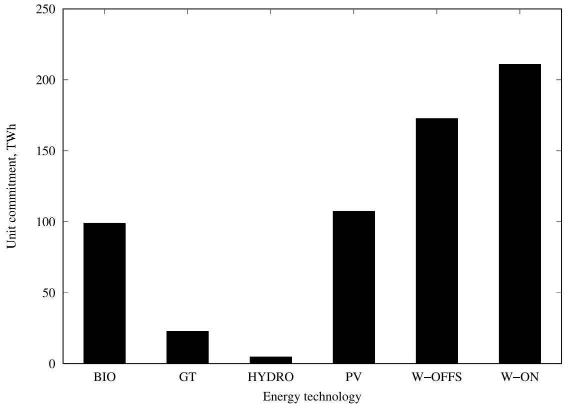

Fig. 4. Unit commitment for reference line setting.

B. Prosumer vs. system - system effects

To illustrate the system level effects through prosumers, we depict $C^{total,*}_{sys}(b)$ and $FCOE(b)$, which we normalize to their respective values at $b = 0$ and $b = 0.47$, respectively; see Fig. 5 and Eq. 18.

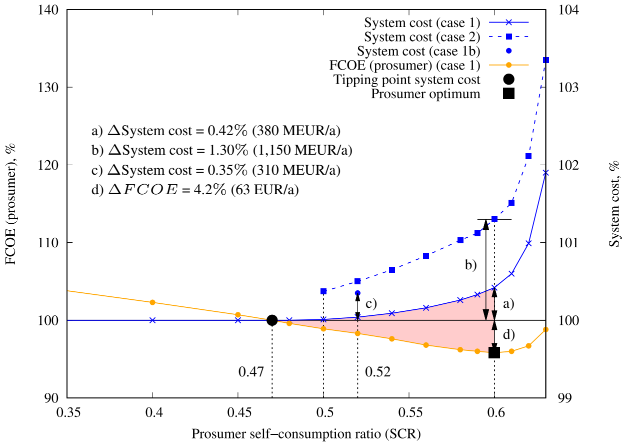

Fig. 5. Normalized system cost versus normalized prosumer $FCOE$ as a function of the prosumer $SCR = b$.

$$\Delta\text{System cost}(b) = \frac{C^{total,*}_{sys}(b)}{C^{total,*}_{sys}(0)} - 1 \tag{18}$$

---

[9] Assumed CO_2 price of 124 EUR/t for 80-95% CO_2 reduction.

[10] Basis: 466 million tons in German electricity sector in 1990, [34].

[11] Percentage figures refer to the annual production without curtailment.

Case 1:
The black circle in Fig. 5 at an SCR of $b = 0.47$ indicates the tipping point of the system (i.e., the maximum allowable prosumer SCR that leaves the total system cost unchanged). The red area indicates the regime where the derivatives of the system cost and prosumer $FCOE$ functions have opposing signs. From a system perspective, prosumer SCRs of 0.47 or below are preferable (i.e., they do not put an additional constraint on the system), whereas prosumers could strive for an SCR of $b = 0.60$ (black square in Fig. 5) to reduce their $FCOE$ by a further 4.2%. The system cost would simultaneously increase by 0.42%, equivalent to 380 MEUR/a. If the same flexibility capacities would be entirely system-beneficially used, then the system cost increase would be slightly lower: 0.35%, equivalent to 310 MEUR/a. However, the SCR would also decrease to 0.52 (Case 1b).

Case 2:
With further restriction of the distributed flexibilities, as in the case of predetermined chronological charging, the system cost would increase by 1.30%, equivalent to 1,150 MEUR/a.[12]
The system cost increase is driven by three effects:

- Decentral storage investments (flexibility redundancies),
- Non-optimal vRES integration, resulting in additional system fuel costs and system CO_2 costs,
- Stress on dispatchable power plants, resulting in additional start-up costs.

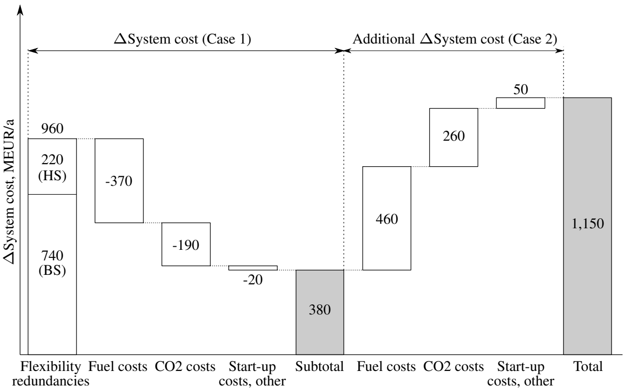

Fig. 6. Break-down of ΔSystem cost for Case 1 and Case 2. Values are rounded to 10 MEUR/a.

Fig. 6 quantifies these effects in more detail. First, higher SCR is realized by more decentralized battery and heat storage capacities, amounting to an overall additional investment of 960 MEUR/a at the system level. This corresponds to an increase of battery content by 3.2 kWh (equivalent to a 740 MEUR/a system cost increase) and an increase of heat storage content by 3.1 kWh (equivalent to a 220 MEUR/a system cost increase) per prosumer household, see Appendix C. Note that this system cost increase is entirely borne by the prosumers themselves. Moreover, the higher storage capacities result in better vRES integration. This, in turn, reduces the unit commitment of dispatchable energy sources and hence results in lower fuel (370 MEUR/a) and CO_2 costs (190 MEUR/a). As a minor effect, start-up costs are also slightly reduced. The overall system cost increase of 380 MEUR/a (Case 1) is hence mainly the result of flexibility redundancies. In this case, additional CO_2 emission savings of approximately 1.3 million tons can be realized. This corresponds to CO_2 abatement costs of 300 EUR/t.

However, the situation changes significantly for the case of the pre-determined chronological charging strategy (Case 2). In this case, the overall vRES integration capability of the system decreases, and dispatchable, fuel-intensive power plants are deployed more strongly. This is also a consequence of efficiency losses through necessary higher pump storage unit commitment. All in all, this results in a fuel cost increase of 460 MEUR/a and a CO_2 cost increase of 260 MEUR/a. Further stress on the dispatchable energy sources results in additional start-up costs of 50 MEUR/a; see also [35], for instance, for a more detailed analysis of this issue. Note that even though the overall flexibility capacities are higher in Case 2 than in the reference line setting, CO_2 emissions increase by 0.5 million tons overall.

C. *Prosumer vs. non-prosumer - allocation effects*

The relative system cost increase is moderate, whereas distributional effects might affect specific stakeholder groups more significantly. This is illustrated by Fig. 7, which depicts the prosumer and non-prosumer $FCOE(b)$s, which are normalized to their respective values at $b = 0$; see Eq. 19. Since the $FCOE$ effects are primarily driven by the SCR and only secondarily by the specific storage operation, we only depict Case 1 in Fig. 7.

$$\Delta FCOE(b) = \frac{FCOE(b)}{FCOE(0)} - 1 \qquad (19)$$

By construction, prosumer and non-prosumer $FCOE$s are equal at zero SCR; that is, all PV production is fed into the public grid at the real-time wholesale price and FiTs fully compensate for the PV investment costs. Fig. 7 illustrates that the $FCOE$ for non-prosuming households increases by 11.6%, equivalent to 197 EUR/a, as a consequence of prosumers maximizing their own profit at an SCR of $b = 0.60$. At the same time, prosumers can reduce their $FCOE$ by 15.2%, equivalent to 262 EUR/a. Overall, this sums up to a deviation of 459 EUR/a between the prosumer and non-prosumer $FCOE$s.

This deviation is driven, foremost, by the regulatory end-customer price components - mainly the allocation of grid costs (275 EUR/a) and vRES support costs (261 EUR/a), as depicted in Fig. 8. These cost increases are partly compensated for by fewer FiT payments at higher SCRs (-184 EUR/a). It is important to note that even at system-optimal SCRs ≤ 0.47, there is still a considerable difference in the cost distribution between prosumers and non-prosumers; see Fig. 7.

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[12] Note that with the installed distributed flexibilities of the reference line setting, an SCR of 0.50 is always realizable, hence the chronological charging curve starts at $b = 0.50$.

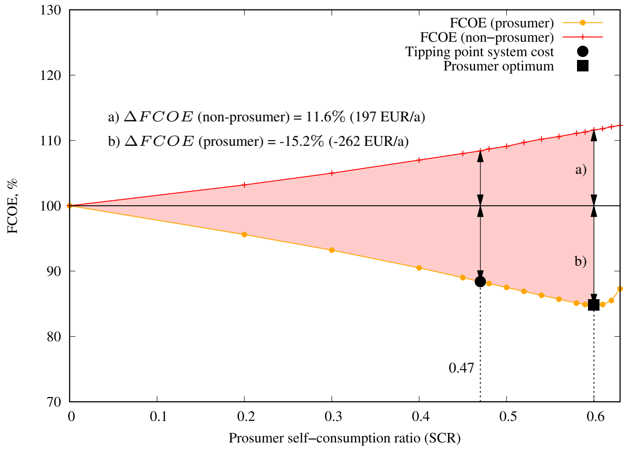

Fig. 7. Normalized $FCOE$ for prosumers and non-prosumers as functions of the prosumer $SCR = b$ (Case 1).

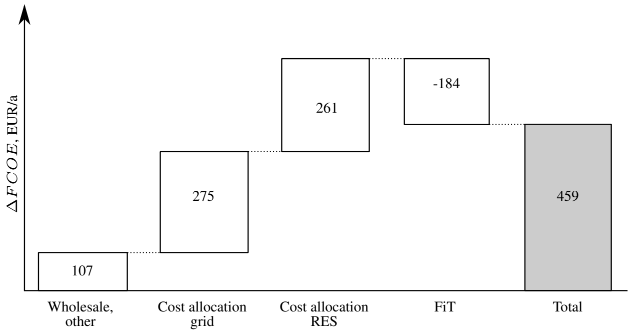

Fig. 8. Break-down of $\Delta FCOE$ (total delta between non-prosumers and prosumers) at $SCR = 0.60$.

D. Interim considerations

Consolidating the results of the system level analysis and the stakeholder level analyses, as depicted in Table III, we derive the following interim considerations.

- In principle, comparably high SCRs ($SCR \leq 0.47$) are achievable without stressing the system. Note that this, however, assumes flexible charging strategies that can adjust to the system.
- However, before effects are present at the system level, individual prosumer and non-prosumer $FCOE$s already deviate significantly from each other (for all $SCR \geq 0$); that is, non-prosumers compensate for prosumers participating less in grid infrastructure and vRES refinancing.

TABLE III
SUMMARY OF RESULTS

	ΔSystem cost	**$\Delta FCOE$**	**$\Delta FCOE$**
	%, (MEUR)	%, (EUR)	%, (EUR)
Case		*Prosumer*	*Non-Prosumer*
1	0.35% (380)	-15.2% (-262)	11.6% (197)
2	1.30% (1,150)	-12.0% (-206)	11.2% (190)

E. Grid effects

One distinguishing feature of prosuming is the local vicinity of demand and production. In general, a local balancing of power should thus be taken into account, especially at the distribution grid level to which most PV power and battery storage systems are connected. Therefore we also evaluate the maximum (hourly) power that is fed into the public grid; see Eq. 20 and Fig. 9.

$$FI_{max}^{Pros} \equiv \max\{FI^{Pros}(t) \mid t \in T\} \tag{20}$$

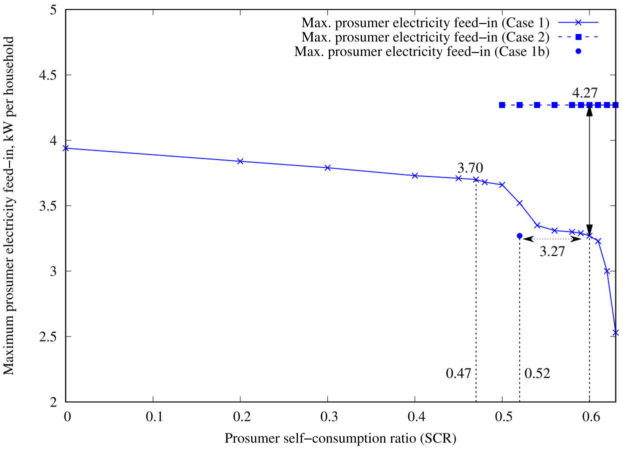

Fig. 9. Maximum electricity feed-in into public distribution grid (per prosumer household), as function of the prosumer $SCR = b$.

With higher SC, FI_{max}^{Pros} decreases from close to 4 kW per prosuming household to 3.27 kW per prosuming household at $SCR = 0.60$. This is the expected result, as the overall installed distributed flexibility of the system increases and can relieve the distribution grid. Grid infrastructure, however, is not based on marginal costs (i.e., the individual prosumer benefit to avoid grid charges does not result one-to-one in overall lower grid costs). This becomes particularly evident for Case 2 (chronological charging). In this case, FI_{max}^{Pros} increases to 4.27 kW per prosuming household, independent of the installed storage capacities. Here, maximum residual loads for the prosumers coincide with both batteries and heat storages being fully-loaded, independent of b. Comparable effects are discussed by [36]. This is also in line with [37], who have stated that the simple restriction of FI_{max}^{Pros} can significantly relieve the (distribution) grid. All in all, this demonstrates that large distributed storage capacities could both put an additional stress on the distribution grid and relieve it. However, especially inflexible charging strategies could increase both wholesale market costs *and* grid costs (as a consequence of needed infrastructure expansion). These costs are, to a large extent, distributed to non-prosuming households.

V. PARAMETER VARIATION ANALYSIS

The order of magnitude of the results crucially depends on four classes of model assumptions. To quantify the effects, we interpret ΔSystem cost and $\Delta FCOE$ (for non-prosumers) as functions ΔSystem cost$(\cdot)$ and $\Delta FCOE(\cdot)$ of these classes, and we discuss the resulting curves. Δs refer in each case to the increase in system cost and $FCOE$ when SCRs rise from $b = 0$ to $b = 0.60$.

Overall system flexibility: At the system level, distortion effects arise from (system) imperfect use of distributed flexibilities. Their impact depends on the overall existing flexibility in the system. Sources of flexibility are other storage sources, most prominently pump storage systems. Interconnections to other countries can constitute a further source of flexibility. As can be seen in Fig. 10, ΔSystem cost increases with increasing central system flexibility, from 0.27% with no additional pump storage capacity present to 0.50% at 30 GW (150% of the base scenario capacity). This is in line with our expectation. With less central storage capacity, the system benefit of distributed flexibilities increases. The more central flexibility that is installed, the more redundant the distributed flexibilities are, resulting in a higher system cost. $\Delta FCOE$ remains nearly constant, as it is mainly driven by the absolute (unaltered) amount of prosumer SC.

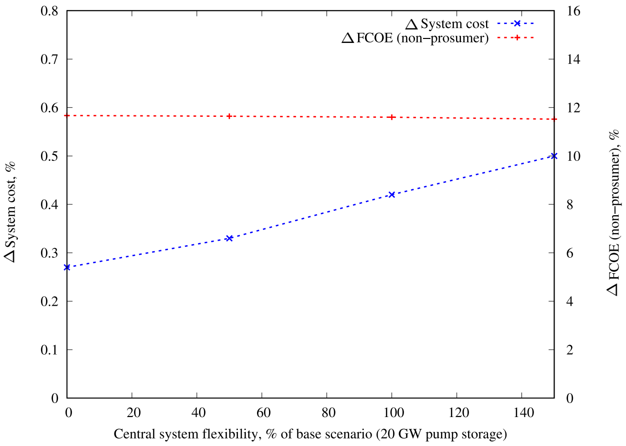

Fig. 10. Variation of overall central system flexibility.

Profiles: vRES production and demand profiles play a major role in the distortion effects at the system level. The determining parameter is the residual load. If the residual loads of prosumers and the central system are congruent, then the prosumer SC maximization results in both optimal PV *and* overall vRES integration. Another factor is the time resolution of profiles. With higher temporal resolution, demand and PV production profiles become sharper. As a consequence, the achievable SCRs are typically lower in reality than estimated in this analysis; see [38] and [39] for instance. In particular, this could reduce $\Delta FCOE$. Furthermore, higher spatial resolution, in combination with the analysis of local simultaneity factors, is crucial to analyze local distribution grid effects. This is, however, beyond the scope of this analysis.

Scaling: Both ΔSystem cost and $\Delta FCOE$ depend on the number of prosuming households that are present in the system. For 1 million prosuming households (5% of the base scenario), both ΔSystem cost and $\Delta FCOE$ are negligible; see Fig. 11. Both ΔSystem cost and $\Delta FCOE$ begin to become relevant at 10 million prosuming households (50% of the base scenario), with ΔSystem cost = 0.16% (140 MEUR/a) and $\Delta FCOE$ = 4.8% (86 EUR/a).

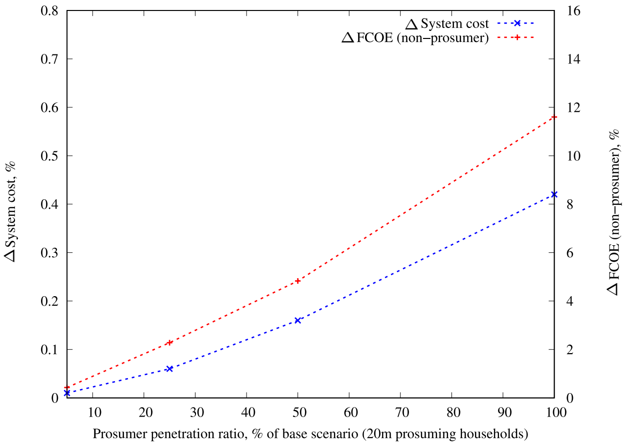

Fig. 11. Variation of prosumer penetration ratio.

Overall parametric uncertainties: Our results ultimately depend on overall parametric uncertainties. To reduce unwanted influencing factors, we use a system model with comparably few input parameters (e.g., restriction to a few technology classes). Amongst other things, specific cost assumptions and technology characteristics, such as power plant efficiencies and full load hours, constitute sources of parametric uncertainty and could potentially impact the absolute values of our results. In the course of this study, we have evaluated various model runs with different parametric settings, such as different (quarter-hourly) household load profiles and different specific cost assumptions. In all these model runs, we could determine the described effects. Combined with the considerations from Section II, we therefore conclude that the effects are of a general nature, and overall tendencies remain unaltered.

VI. CONCLUSION

The transformation of the energy system towards a 100% RES system strongly depends on energy sources with low energy density and hence a distributed character. Prosumer integration in a system-compatible manner, which takes into account the effects on non-prosuming households, is of special importance. However, our analysis of an electricity system with high RES and prosumer shares demonstrates that the interplay of common regulatory market framework instruments could lead to distortion effects at both system and stakeholder levels. These effects should be considered when developing the regulatory market framework further, to guarantee a working integration of both active market participants and non-prosuming households. We summarize our findings by highlighting four aspects:

1) Prosumers can produce and integrate vRES into the energy system and constitute a source of vRES investment (financing capital). Higher SC, as strived for by the prosumers, can indeed lead to better vRES integration and CO_2 emission reduction. The increase in system cost is mainly covered by the prosumers themselves.

2) However, the annual SC is only one determining parameter and still leaves comparably high degree of freedom to the system.[13] In the case of entirely inflexible storage operation modes, vRES integration could decrease, and CO_2 emissions and system cost could increase significantly when prosumers strive for their individual economic optimum.
3) On the one hand, higher storage capacities, operated at least to some extent in a grid-beneficial manner, could relieve distribution grids, even at high SCRs. On the other hand, if SC is maximized in an inconsiderate manner, then there is a potential threat of additional stress on the grid, possibly resulting in a further system cost increase.
4) Distributional effects at a high prosumer SC level are particularly significant. Regulatory allocation mechanisms incentivize the maximization of prosumer SC, which, in turn, can create an additional burden on non-prosumers in the double-digit percentage range. This becomes even more relevant in view of the overall energy system transformation leading to a shift from operating expenditures (OpEx) to capital expenditures (CapEx). Prosumers can utilize their CapEx to maximize their profit; meanwhile, non-prosumers are forced to compensate with higher OpEx.

The distributional effects comprise the recovery of fixed costs both for RES and for transmission investments. Accordingly, a high number of prosumer households in combination with high SCRs do not only lead to an increase in the specific RES support costs, but also to higher network charges, at least if allocated volumetrically. In this paper, the transmission investments are included as exogenous model input. Future work could depict the transmission investments model-endogenously, in order to analyze the interplay of possible cost-reducing and cost-pushing effects through SC.

The quantified distortion effects are of a general nature for allocation-based refinancing schemes, leading to unequal treatment of SC and the wholesale market. The effect bears resemblance to artificial network congestions, causing inefficiencies that burden both the system in general and non-prosuming households specifically. By quantifying these effects in an integrated assessment, we demonstrate that they could be relevant in systems with both a high RES *and* prosumer shares. The distributional effects, in particular, might constitute a potential threat for the overall acceptance of the energy system transformation. However, the findings depend on a certain regulative way in which to distribute costs to end-customers. Based on this work, the research could be extended to an analysis of alternative regulatory schemes (e.g., capacity-based grid charges).

The analysis exhibits several limitations that require further research. Most prominently, local network load effects should be analyzed in more detail by means of a higher spatial resolution. Furthermore, the effects of widespread electromobility have not been included in our analysis but could be analyzed in future work.

APPENDIX A
SYSTEM COSTS VECTOR

The components of the cost vector c are given as follows:

$$\begin{aligned}
c_{inv} &= c^{l}_{inv}(pp_r) \cdot AF(pp_r) + c_{fOaM}(pp_r) \\
c_{prod} &= c_{vOaM}(pp_r, t) + c_{fuel}(pp_r, t) + c_{CO_2}(pp_r, t) \\
c_{start} &= c_{start}(pp_r, t) \\
c_{sto} &= c_{sto}(sto_r, t) \\
&\forall pp_r \in PP, sto_r \in STO, r \in R, t \in T
\end{aligned} \tag{21}$$

AF denotes the annuity factor. Moreover, c_{start} contains the costs for a power plant start-up including additional fuel and CO_2 costs. Fuel costs and CO_2 costs are given as primary energy prices (BIO: 18.75 EUR/MWh; GT: 35.76 EUR/MWh) divided by power plant efficiency (BIO: 0.46; GT: 0.40) (fuel costs), and CO_2 emissions factor (GT: 0.202 t/MWh) times CO_2 price divided by power plant efficiency (CO_2 costs), respectively.

APPENDIX B
FURTHER SYSTEM MODEL RESTRICTIONS

Production restrictions:

$$\begin{aligned}
x_{prod}(pp_r, t) &\leq x_{on}(pp_r, t) \cdot MaxPower(pp_r) \\
x_{prod}(pp_r, t) &\geq x_{on}(pp_r, t) \cdot MinPower(pp_r) \\
x_{inv}(pp_r) &\geq x_{on}(pp_r, t) \cdot MaxPower(pp_r) \\
x_{start}(pp_r, t') &\geq (x_{on}(pp_r, t') - x_{on}(pp_r, t)) \cdot MinCap(pp_r) \\
\forall pp_r \in PP, r \in R &\text{ and } t, t' \in T, t' - t = 1
\end{aligned} \tag{22}$$

The maximum production capacity per power plant class is restricted by the corresponding investment. A dispatchable power plant can change its momentary production within $MinCap$ and $MaxCap$ without additional costs. Increasing production capacity from 0 to $MinCap$ incurs additional start-up costs as this implies change of $x_{on}(t)$.

APPENDIX C
STORAGE CAPACITIES

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[13] Only the overall time-integral serves as model constraint, specific hourly flexibility states (fill levels) are not restricted directly.

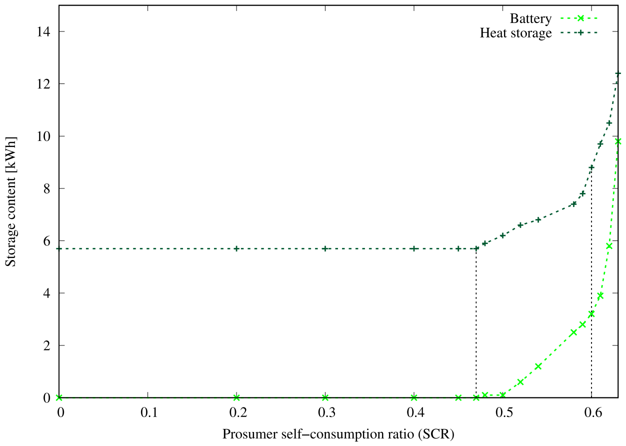

Fig. 12. Storage content sizes of battery and heat storage as functions of the prosumer $SCR = b$, per prosumer household (Case 1).

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Kai Hufendiek has been appointed full professor and head of the University of Stuttgart’s Institute of Energy Economics and Rational Energy Use (IER) since October 2014. His main research focus encompasses holistic energy system analysis and analysis of energy markets and smart distributed energy systems. Moreover, he has studied engineering at the University of Stuttgart and at the University of Manchester Institute of Science and Technology (UMIST), and he received a Master’s in 1994 and a Dipl.-Ing. degree in 1995. He acquired his Ph.D. from the University of Stuttgart in 2001, with a thesis on load forecast methods with neural networks. Thereafter, he gained experience in different management positions at a large German energy company where he developed numerous model-based methods, for example, for analyzing prices at different energy markets including the emerging emissions trading.

5 Paper C

5.1 Author contributions

Table 5-0 shows the contributions of the co-authors of Paper C, based on the representative roles according to the Contributor Roles Taxonomy (CRediT).[12]

Tab. 5-0: Author contributions for Paper C: Impact of network charge design in an energy system with large penetration of renewables and high prosumer shares

	Paper B		
	Christoph Schick	Nikolai Klempp	Kai Hufendiek
Conceptualization	✓		
Methodology	✓		
Formal analysis	✓		
Software	✓		
Data curation	✓		
Validation	✓		
Visualization	✓		
Writing - original draft	✓		
Writing - review & editing		✓	✓
Supervision		✓	✓

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[12] See https://credit.niso.org/ for further details.

5.2 Impact of network charge design in an energy system with large penetration of renewables and high prosumer shares

energies

MDPI

Article

Impact of Network Charge Design in an Energy System with Large Penetration of Renewables and High Prosumer Shares

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Abstract: The transformation of our energy system toward zero net CO_2 emissions correlates with a stronger use of low energy density renewable energy sources (RES), such as photovoltaic (PV) energy. As a source of flexibility, distributed PV systems, in particular, are oftentimes installed in combination with battery storage systems. These storage systems are dispatchable, i.e., controllable by the operating owners, who can thereby take over an active market role as energy prosumers. The particular battery operation modes are based on the individual prosumer decisions, which, in turn, are strongly affected by the regulatory framework in place. Regulatory frameworks differ from country to country, but almost all regulatory frameworks feature a network charge mechanism, which allocates network infrastructure and operating costs to the end customers. This raises the question of the extent to which different network charges lead to different prosumer decisions, i.e., battery operation modes, and thus different energy system configurations (system costs). In order to evaluate this question we apply (a) a fundamental linear optimization model of the energy wholesale market, which we stringently link to (b) an analysis of peak-coincident network capacity utilization as well as (c) an evaluation of the complete costs of energy for prosumers and consumers. This stringent cycle of analysis is applied to two prototypical network allocation schemes. We demonstrate that network allocation schemes that are orientated to peak-coincident network capacity utilization could both better incentivize a distribution network-oriented behaviour and better share financial burdens between prosuming and purely consuming households than would be the case for volumetric network charge designs. This paper further demonstrates that network-oriented battery operation does not, per se, result in optimal RES integration at the wholesale market level and CO_2 emissions reduction. To identify effects from increasing sector integration, an analysis is both performed for a setting without and with consideration of widespread e-mobility. As a broader conclusion, our results demonstrate that future regulatory frameworks should have a stronger focus on prosumer integration by means, among other things, of an adequate network charge design reflecting the increasingly distributed nature of our future energy system.

Keywords: prosumers; regulatory framework; grid charge mechanisms; energy system modeling

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1. Introduction

The shift from a conventional, centralized electricity production to a more distributed generation of electricity brings numerous distributed stakeholders into play who evolve from passive energy consumers to active market participants (prosumers) (Parts of this paper were originally presented at the 1st IAEE Online Conference; see [1]. However, this manuscript provides a substantial extension of results, analysis and conclusions over the conference proceedings paper, including a comprehensive overview of the state of the art, consideration of different prosumer penetration ratios, and analysis of the impact of widespread e-mobility. Sections that have been adopted from [1] are explicitly identified in this paper. The introduction section itself is adopted in parts from [1]). Distributed PV power systems, in combination with controllable flexibility elements such as battery storage units, are expected to play a major role, in particular. While prosumer storage capacities can provide a necessary source of needed flexibility in general, in reality, these flexibilities oftentimes operate inflexibly for individual profit maximization. In principle, three prototypical battery operation modes can be distinguished as follows:

1. Distributed flexibilities can operate for individual profit maximization, depending on the regulatory framework. This oftentimes equals self-consumption maximization; scope of analysis: n = one household;
2. Distributed flexibilities can operate (distribution) network-beneficially, reducing peak-coincident network utilization; scope of analysis: n = tens to hundreds of households;
3. Distributed flexibilities can operate market beneficially to leverage portfolio effects for optimal RES integration at the wholesale market (system) level; scope of analysis: n = thousands to millions of households.

In principle, prosumer households could have direct market access and participate individually and independently in the energy market. Another option is that several prosumer households join together to form (virtual) prosumer associations, energy co-operatives, or the like. In both cases, the prosumer behaviour is strongly driven by the specific policy instruments in place. Among these instruments, network charges play a crucial role in view of re-financing network operation and infrastruture costs. For regulatory frameworks with volumetric network charges, profit maximization oftentimes results in self-consumption (SC) maximization. However, from a system perspective, SC maximization by means of predetermined prosumer heuristics results in overall flexibility reduction, potentially burdening both the distribution network and the wholesale market; see [2]. The basic idea of our research approach is to analyze these effects for two exemplary network charge mechanisms. The novelty value of this study consists in a fully stringent consideration of individual end-user effects (energy bills), local network aspects and global system (wholesale market) impacts. This way, our approach combines the analysis of social needs (e.g., allocation of network costs), the analysis of technical aspects (e.g., peak-coincident network capacity utilization), and the analysis of system effects (e.g., RES market integration at the wholesale market level).

1.1. Previous Works

The relevant existing literature for this study can be divided into three groups. The first group of studies deals with the general theory of network charge design and/or analyzes particular network cost allocation mechanisms in view of individual end-consumer aspects. The second group of studies analyzes local distribution network aspects in the presence of high shares of distributed prosumer generation. The third group of studies takes on a system perspective to evaluate the impact of distributed prosumer generation at the (wholesale) market level.

1.1.1. General Theory of Network Charge Design and Individual Aspects

Network charges fulfill different functions in the energy system; most importantly:

- As their primary objective, network charges are the instrument of re-financing network operation and infrastructure to guarantee fixed-cost recovery;
- Moreover, network charges can constitute a steering element for the system-beneficial operation of flexibilities. System-beneficial operation may involve both grid- and market-oriented behaviour, which could coincide, but could also conflict. In other words, network charges should ideally provide an efficient, economic signal to end users in the system.

An overview of the existing network charge mechanisms of selected European countries is provided by [3], for instance. Studies such as [4,5] provide a more conceptual overview of existing network charge mechanisms. The latter classifies network charge mechanisms into three clusters: nodal marginal methods (nodal marginal pricing), rolled-in methods via postage stamp and mean participation factors, and embedded methods based on power flow analysis, such as MW-mile methods. These methods are not necessarily mutually exclusive but can come in combinations. Ref. [6], for instance, discusses that nodal marginal pricing is not able to recover the full network costs in reality and evaluates a combination of locational marginal pricing and rolled-in methods. The authors study mean participation factors as a particular rolled-in method, based on a cost causality (or "extent of use") principle. The basic idea is to allocate complementary network costs (i.e., the remaining part of the network costs after marginal network pricing) to system users according to their individual contributions to each line flow of the network. This method has been considered or finally applied in reality, albeit only sporadically. One important and widely used (e.g., in the ENTSO-E) alternative is volumetric network charges, i.e., fixed charges per unit energy transmitted via the public grid. They belong to the class of postage stamp methods (i.e., the network charge is independent of the actual electricity transmission distance). Their widespread use is also due to their technical simplicity. However, the problem with volumetric network charges is that they do not properly comprise cost causality; see [7], for instance. This is due to the fact that grid infrastructure, in particular, is not based on marginal costs; i.e., the individual avoidance of grid charges does not result one-to-one in overall lower grid costs. Further analysis of rolled-in network charges is provided by [8], who evaluate different exogenous network charge mechanisms (equal sharing, allocation by electrical distance, zonal cost allocation) for a consumer-centric peer-to-peer market framework, illustrated on a 39-bus system. This paper demonstrates that relatively simple (and transparent) exogenous cost allocation mechanisms can, in principle, incite a network-beneficial prosumer behaviour. The earlier mentioned MW-mile method is the first of the power flow-based pricing strategies that considers the actual network use; see [9]. The core idea is to allocate transmission costs per line length of transmission and per power flow per line. This method encourages an efficient network use; however, it is complicated to realize, as it requires multiple power flow calculations. Further improvements of this method could also consider the load quality, distinguishing between reactive and active power. Moreover, one could also base the method on current flows instead of power flows; see [10]. Ref. [11] analyzes uniform marginal prices (as opposed to locational marginal prices), which they derive from a maximum social welfare condition on the basis of a 42-bus test distribution network. They demonstrate that such uniform, but time-varying, prices can send efficient signals to end customers to optimize grid operation (e.g., high peak load prices). This study is relevant for our analysis in that we will take on the concept of peak-load pricing; however, we will add a consideration of system effects and allocation aspects between different customer groups.

A couple of studies have a particular focus on the impact of prosumers on network tariffs. Studies such as [7,12] discuss the problem of cross subsidies from consumers to prosumers with volumetric network charges. Ref. [7] discusses that volumetric network charges can lead to cross subsidies, which burden consuming (when we use the term consumers/consuming households, we refer to non-prosuming households throughout the manuscript) households in the presence of self-consuming prosumers. This is a direct result from the option of prosuming households to cover a part of their electricity demand by their own PV production (SC), which is exempt from regulatory cost allocations such as network charges. As a consequence, total network costs are allocated to fewer households (or, to be precise, there is a lesser amount of energy withdrawn from the grid), leading to higher specific, and in the case of consuming households also higher absolute, network charges. Ref. [12] specifically analyzes the effect of widespread distributed generation on network tariffs in the context of cost allocation between different costumer groups of prosuming and consuming households. The authors demonstrate that volumetric tariffs in combination with prosumer net metering can rise significantly with increasing PV penetration due to the above-mentioned effects. Consequently, the authors conclude that such network tariffs do not properly reflect cost causality originating from load- and PV-driven costs. Ref. [13] further analyzes equity issues between prosumers and consumers by means of a non-cooperative game for the network cost recovery in view of different rate designs including volumetric and capacity-based network charges. All of these studies provide valuable insights regarding the design of different network charges on their local impacts. However, they do not (aim to) analyze system level effects to a full extent; i.e., simulation or optimization is restricted to the local grid.

1.1.2. Analysis of Local Distribution Network Systems with High Distributed Generation

A range of studies analyze local distribution networks, in many cases on the basis of specific n-bus systems. Ref. [14] provides a review of the impacts of high PV penetrations in low voltage distribution networks, including a discussion of several (mostly technical) mitigation techniques. Amongst other methods, they discuss distributed battery storage systems, which can be operated for load leveling (energy is stored in a battery when grid power exceeds load demand and vice versa), arbitrage mode (energy is purchased at off-peak and utilized during peak hours) or export curtailment mode (excess PV generation is stored into battery storage). However, given the status of a review paper, the authors do not provide an actual system analysis to determine in what way the different operation modes could actually contribute to network stress reduction—which we address in our paper. Ref. [15] provides a range of technical tools and methodologies to investigate the steady-state as well as dynamic impacts of widely spread distributed PV generation on the distribution network, such as reverse power flows and voltage fluctuations. Ref. [16] evaluates the impact of distributed battery storages on low-voltage distribution networks, especially in view of inverse power flows. The authors demonstrate that there is a conflict of interests between distributed battery owners and network operators. They demonstrate that for certain inflexible storage operation strategies, which aim at SC maximization, high stress is induced on the distribution network. This is a consequence of high feed-in peak times, which occur when peak PV generation meets batteries already fully charged. When batteries are operated to absorb peak generation, the distribution network can be relieved, however, at the cost of lower individual SC. Ref. [17] analyzes voltage stability for residential customers in distribution networks with high small-scale grid-connected PV penetration. According to their analysis of a local 13-bus system network, voltage instability typically occurs for PV penetration levels $\geq$40% The authors also investigate the impact of distributed battery storage systems, demonstrating that batteries can maintain voltage stability in general. However, reduction of voltage instability crucially depends on the local positioning of the batteries within the network. Again, the mentioned papers provide valuable insights regarding the impact of distributed generation and battery storage. However, the authors do (a) not provide a full system perspective to determine in what way the battery operation modes impact the wholesale market, and (b) do not fully evaluate the individual end customer costs of electricity and allocation aspects between different end-user groups.

1.1.3. Analysis of System Impacts

A third group of studies analyze system-level impacts in the presence of high prosumer shares. Ref. [18] analyzes different aspects of alternative network charge designs, modelling both customer bill and system operational costs. In particular, they compare volumetric network charges with a design that includes peak-coincident network capacity charges (EUR/kW) and Ramsey-like allocation of the residual network costs (e.g., fixed charges per customer in EUR/user). They argue that a design based on peak-coincident network capacities constitutes an efficient ideal approach, in that such a design incites the network users to relieve the grid, in contrast to volumetric charges, which incite SC maximization. On top of this, their suggested design avoids direct interference with energy prices [EUR/MWh] and therefore minimizes economic distortion effects. They demonstrate that this approach both leads to the lowest end customer bill and leads to the greatest reduction of marginal system costs. This paper is of special importance for us in that we apply the suggested construction of capacity charges to our closed-loop analysis. Energy cooperatives, such as those analyzed by [19], could represent a particularly interesting level of aggregation and could play an important role for effective prosumer integration into the energy system. Another approach to combine the individual household and system perspectives is provided by the authors of [20], who analyze the role of electric SC in view of distinct levels of aggregation. The authors demonstrate by means of an energy supply system optimization that self-sufficiency at the individual household level is economically favorable only at decent degrees (around 30%). At higher aggregation level ($\geq$560 households), however, full self-sufficiency could be economically advantageous. The authors conclude that this is a consequence of system-oriented battery operation in combination with profile smoothing effects, such as a reduction in demand fluctuation and reduction of peak loads. However, these studies are limited in that the system analyses crucially depend on exogenous model assumptions such as exogenous time series of wholesale market prices. Moreover, quantification of distributional effects between prosuming and consuming households is missing. Finally, ref. [21] reviews a total of 359 studies that deal with system modelling of decentralized energy autonomy. The authors conclude that (a) studies generally lack an evaluation of the impact of autonomous systems (such as prosumers striving for SC maximization) on the surrounding system and (b) local stakeholders need to be considered methodologically. Both aspects are crucial parts of this paper and will be focused on in the following.

1.2. Our Contribution

The aim of our analysis is to study the impact of high shares of energy prosumers under consideration of two different network charge mechanisms. The first mechanism, volumetric network charges, is representative for a widespread status quo, whereas the second mechanism, peak-coincident capacity network charges, represents a potential future scheme in order to integrate distributed PV and battery systems more efficiently. The novelty value of this manuscript lies in the simultaneous consideration of end-consumer effects, distribution network effects, and wholesale market effects under the realistic depiction of relevant regulatory aspects of the electricity retail market. According to our knowledge, such an integrated view of network charges has not yet been carried out. Key questions to be answered in this study are:

- **Individual stakeholder level:** In what way do certain network charge mechanisms contribute to distributive justice, e.g., fair allocation of costs among prosuming and consuming households?
- **Distribution network level:** In what way can certain network charge mechanisms contribute to steer network-beneficial, i.e., grid-relieving, behaviour?
- **Wholesale market level:** In what way do local distribution network relief (e.g., reduction of peak-coincident network capacity utilization) and global wholesale market benefits (e.g., optimal RES integration) coincide or conflict?

2. Materials and Methods

This study's approach involves establishing a closed-loop analysis of prosumer battery operation and an analysis of the resulting full costs of electricity (FCOE) (The following materials and methods section is taken from [1] and slightly adapted and complemented). Additionally, the process includes an analysis of network capacity utilization and a study of the resulting total system costs. These are examined using a fundamental linear optimization model for the three flexibility operation modes (denoted by 1, 2, 3 and further defined in the following sections; see Figure 1). For the FCOE analysis, the study applies quarter-hour household profiles on the basis of real generated measured data. This is a key feature of this study and is in contrast to several other studies that apply synthetic, and already aggregated, household profiles for electric demand and PV production. The FCOE contain the levelized cost of energy (LCOE: annualized fixed and variable costs of energy) and regulatory network charges under the consideration of two different allocation schemes.

- **Volumetric network charges**
- **Peak-coincident network capacity charges**; as detailed by [18]

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

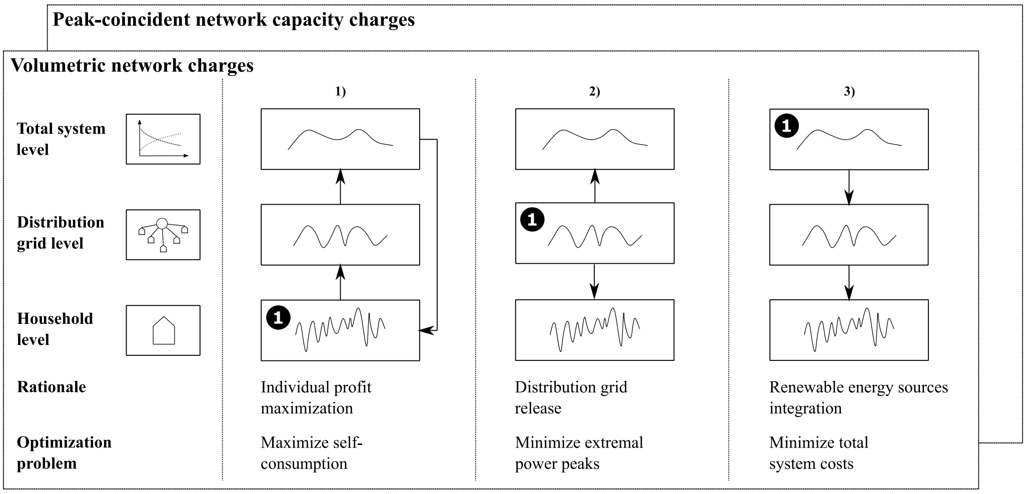


Figure 1. Workflow of analysis; encircled "1" denotes the starting point of analysis, corresponding to the respective battery operation mode (1, 2, or 3).

Finally, the residual load profiles are further smoothed to generate aggregated wholesale market profiles. These residual load profiles enter a linear optimization model of the electricity market, which minimizes the total system costs. Each battery operation mode leads to a different residual load profile at the wholesale market level and thus to a different system optimum. In this analysis we focus on three prototypical battery operation modes, namely:

- **Operation mode 1**: Objective: Maximize prosumer SC. In this case, the battery is operated according to a static, predetermined prosumer heuristic, which ensures a maximum consumption of self-produced electricity;
- **Operation mode 2**: Objective: Release distribution grid. The battery is, again, operated in order to maximize prosumer SC. In this case, however, SC maximization is implemented as a linear optimization problem with a grid-releasing constraint in order to reduce peak-coincident network capacity utilization;
- **Operation mode 3**: Objective: Minimize system (wholesale market) costs. In this case, the battery is operated market-beneficially, i.e., the battery reacts fully flexibly to the real-time wholesale market price signal.

Instead of looking at individual prosumer households with direct market access, one could also consider the association of several households into energy cooperatives. This bundling of decentralized flexibilities would, in a sense, form an intermediate level between the individual households and the wholesale market. Even though such energy cooperatives would partially enable different battery operation modes than considered in this paper, the general distinction between individual optimization (either at the individual household or the cooperative level), grid orientation and wholesale market orientation remains valid.

2.1. Battery Operation Mode 1: Maximization of Prosumer Self-Consumption

2.1.1. Battery Operation

The rationale behind battery operation mode 1 is to maximize prosumer SC. Generally, there is a countable set of algorithms that can accomplish this objective. In this manuscript, an algorithm is used that is referred to as “chronological charging”; see [2]. This algorithm promotes the use of self-produced electricity whenever possible, either directly for momentary consumption or indirectly for charging the prosumer battery. A pseudocode is provided in Appendix A (Algorithm A1), with variable and parameter descriptions provided by Table 1. This algorithm can be interpreted as the canonical implementation of SC maximization. Regarding the data input, the electric load profile is provided by measured data of a single-family household in the German city Düsseldorf with a temporal resolution of 15 min; see [22,23]. The PV production profile is provided by a PV plant in the Stuttgart area with a temporal resolution of 15 min.

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

	Description	Unit	Value	Source
Variables				
fi	Feed-in of (surplus) PV production	[kW]	*Output*	-
gs	Grid load	[kW]	*Output*	-
$BattFillLevel$	Fill level of battery	[kWh]	*Output*	-
Parameters				
ResLoad	Prosumer load—PV production	[kW]	Exogenous time series	[22,23]
TimeRes	Time resolution of modelling	[h]	0.25	Model parameter
BattPower	Battery discharging power	[kW]	3	Assumption
BattCharging	Battery charging power	[kW]	3	Assumption
BattContent	Maximum battery storage content	[kW]	6	Assumption
Further data				
DemandElec	Annual electricity demand	[kWh]	4000	Assumption
FLH	PV full load hours	[h/a]	1050	Assumption
N	Number of households	[MN]	40	Assumption

The outputs from this algorithm are time series for the prosumer grid supply, $gs(t_n)$, and feed-in, $fi(t_n)$, which can be consolidated in one time series, referred to as the prosumer residual load (throughout this paper, the notion of residual load refers to the residual load after battery operation, to be distinguished from ResLoad = prosumer load − prosumer PV production) and denoted by $RL(t_n)$, as shown in Equation (1).

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

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

$$FCOE = \underbrace{c_{inv} \cdot x_{inv}}_{\text{investment costs}} + \underbrace{\overline{\lambda} \cdot (GS - MVF \cdot FI)}_{\text{market costs}} + \underbrace{f(\ldots) \cdot c_{network}}_{\text{network costs}} \tag{2}$$

In this equation, c_{inv} represents the specific investment cost vector including PV and battery investment costs with parameters set as shown in [2], whereas x_{inv} contains the installed PV and battery capacities; see Table 1. $\overline{\lambda}$ represents the average (wholesale) market price (In general, λ follows as a dual variable of the load coverage restriction as model-endogenous output. In this study, we consider a (constant) mark-up of 120 EUR/MWh on top of the wholesale market price which is, in particular, high enough to enable prosumers to refinance their investments into PV entirely through the market price); GS and FI

stand for the annual amounts of energy withdrawn from the grid (GS: annual grid supply; $GS = \sum_n gs(t_n)$) and fed into the grid (FI: annual feed-in; $FI = \sum_n fi(t_n)$), respectively. The market value factor MVF accounts for the actual PV wholesale market value and is assumed to be 50% in this study. The last term in Equation (2), $c_{network}$, represents the specific network costs (either per kWh in the volumetric case or per kW in the case of peak capacity charges); see Section 2.1.3. Elsewhere, $f(\dots)$ is specified in the following chapter as either a function of the volume (volumetric network charges) withdrawn from the grid or as a function of the peak-coincident power withdrawn from or fed into the grid (peak capacity charges).

2.1.2. Network Utilization

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

- The assumption of a radial distribution network topology;
- The consideration of thermal stress on components only, neglecting other aspects, such as voltage unbalance or the like; see [24], for instance. That is—we only consider the network resistance R, neglecting its reactance X and phases, which seems to be justified by usually high R/X ratios in distribution grids; see [14], for instance.
- The use of prototype (residual) load profiles. That is, rather than aggregating multiple real generated measured profiles, in this study we use one single load profile and one single PV profile as the starting point and account for simultaneity effects in a separate analysis step as described in the following paragraphs. This is a strong simplification—however, for our purposes, we are only interested in the relative change of the maxima of the aggregated residual load resulting from different battery operational modes. This purpose seems to be attainable by our approach.

To be precise, this study assumes n households to be connected to a network node, of which a share of ρ are assumed to be prosumers and a share of $1-\rho$ are assumed to be traditional consumers. To quantify the actual residual load on the network node, one must first smooth the sharp prosumer and consumer household (residual) load profiles (consumer residual load RL_{Cons} = consumer load), as described in the next paragraph, denoted by a bar in this paper, to account for simultaneity effects. Second, the smoothed prosumer and consumer profiles ($\overline{RL}_{Pros}, \overline{RL}_{Cons}$) are superposed according to their respective penetration ratios, resulting in the actual network node residual load RL_{Node}; see Equation (3) and Figure 2.

$$RL_{Node}(t) = n \cdot (\rho \cdot \overline{RL}(t)_{Pros} + (1-\rho) \cdot \overline{RL}(t)_{Cons}) \tag{3}$$

Profile smoothing is performed using Gaussian smoothing (also referred to as Gaussian blur in other fields, such as image processing). It begins from a given (sharp) initial residual load profile and generates further residual load profiles by shifting the initial profile values to the left and right (in the temporal dimension). For the aggregation, shift probabilities are weighted by a Gaussian normal distribution, as shown in Equation (4).

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

The maximum power peak of the aggregated residual load profile is usually lower than the sum of the maximum power peaks of the individual residual load profiles. The ratio of these two quantities is referred to as the simultaneity factor, g, which is a function of the number of profiles n that are aggregated, $g = g(n)$. In other words, the simultaneity factor quantifies by how much the aggregated profile is smoother than the non-aggregated profile. In the literature, there are numerous (partly contradictory) theoretical and empirical derivations of the functional dependency of $g(n)$. In the following, we refer to [25], according to which the n-dependency of the simultaneity factor is given by Equation (5).

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

Applying $\sigma = \sqrt{n}$, Figure 3 demonstrates that the applied Gaussian smoothing is indeed in asymptotical accordance with the theoretical functional $1/\sqrt{n}$ dependency; see Appendix B for further details. For the distribution network level, we use $\sigma = \sqrt{n} \in \{7; 10; 14\}$, formally corresponding to $n \in \{49; 100; 196\}$ households per node.

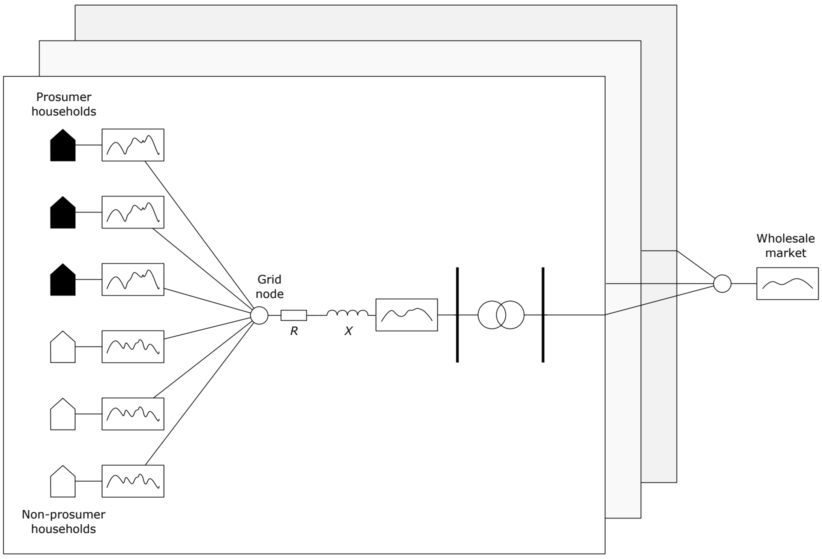


Figure 2. Schematic sketch of distribution network analysis. Sharp single-household load and production profiles from prosuming and consuming households result in smoothed residual load profiles on the distribution network node, taking into account simultaneity effects. Electrical energy is then further transferred via transformers to the transmission grid. Total supply and demand within the wholesale market zone exhibit further profile-smoothing portfolio effects.

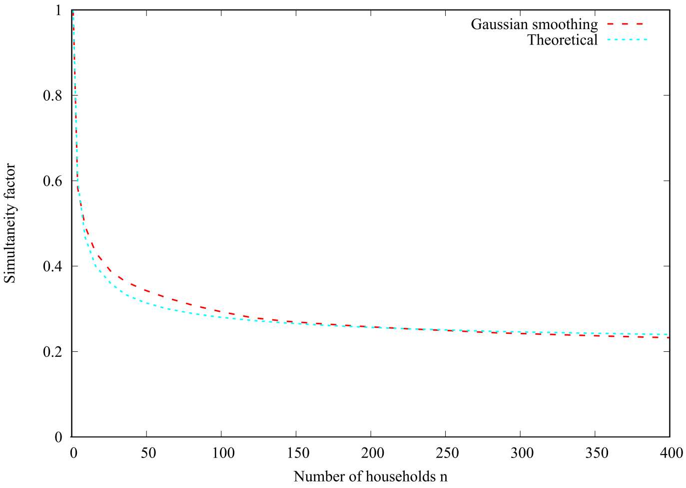


Figure 3. Comparison of simultaneity factors resulting from Gaussian smoothing and theoretical values with $g_\infty = 0.2$.

2.1.3. Network Charges

In this study, we evaluate the effect of two different network cost allocation schemes: volumetric (network consumption based) network charges (*VNC*) and peak-coincident network capacity utilization charges (*CNC*). For the construction of the *VNC*, we apply the same approach as detailed in [2]. This is, the absolute amount of annualized grid infrastructure and operation cost is allocated to the end customers per energy withdrawn from the grid; see Equation (6).

$$VNC = GS \cdot c_{network}^{vol} \tag{6}$$

In this study, we have explicitly considered the effect of prosumer SC, which increases the specific volumetric network costs as a consequence of a reduced network cost allocation base. Technically speaking, the value for $c_{network}^{vol}$ in Table 2 refers to a setting of 25% prosumer penetration ratio and market-compatible battery operation (operation mode 3). For other combinations of prosumer shares and battery operation modes, the specific network costs are adjusted such that the total network cost refinancing sum remains unchanged; see [2] for further details. For the technical realization of the *CNC* in this study we refer to [18], who suggest taking into consideration the top 30 highest (residual) load peaks. As suggested in their paper, the *CNC* are calculated ex-post on the basis of a historic network load time series; see Equation (7). This approach is reasonable in that such anticipated peak situations (rather than actual peaks) guide (long-term) network investments. The reason for using the top 30 (instead of the single) highest demand peaks is to reduce the randomness in the application of the allocation mechanism to a certain extent; see [18] for a detailed discussion.

$$CNC = \overline{RL^{peak}} \cdot c_{network}^{peak} + C_{network}^{fixed} \tag{7}$$

Moreover, the peak capacity charges are complemented by an additional fixed charge per customer. This is due to the fact that a network cost refinancing which is purely based on peak-coincident capacity charges could necessitate excessively high network charges. Fixed network charges per customer are thus added to compensate for the residuum between total network costs and refinancing carried out through capacity charges. Variable description and parameter setting is provided in Table 2.

Table 2. Summary of used variables and parameters for network charge modelling.

	Description	Unit	Value	Source
Variables				
$\overline{RL^{peak}}$	Average of (prosumer/consumer) residual load over top 30 highest residual load peaks at network node	[kW]	*Output*	-
$C_{network}^{fixed}$	Fixed network charge per customer	[EUR/p.c.]	*Output*	-
Parameters				
$c_{network}^{vol}$	Specific volumetric network charges	[EUR/MWh]	50	Assumption
$c_{network}^{peak}$	Specific network capacity charges	[EUR/kW]	100	Assumption

2.1.4. System Modelling

This study determines the total system (wholesale market) costs by using a fundamental linear optimization model of the European electricity market, the European Electricity Market Model, E2M2; see [26] for a detailed overview. E2M2 is a combined (mid-/long-term) investment and unit commitment model. The dual variable of the demand coverage restriction can be interpreted as the wholesale market price. The model has hourly temporal resolution, which is appropriate when system costs are solely of interest, as is the case with this study; see [27]. In [2], there is a detailed description of the model structure and parameter settings which are used in this paper, including the cost vector c^T and the decision variable vector x. The residual load as an aggregation of all prosumer and consumer households enters the system model, as an (from a system perspective) exogenous time series; see Equation (8).

$$RL_{total}(t) = N \cdot (\rho \cdot \overline{\overline{RL}}(t)_{Pros} + (1-\rho) \cdot \overline{\overline{RL}}(t)_{Cons}) \tag{8}$$

For the profile aggregation at system level, indicated by the double bars in the equation above, the study applies the same methodology, Gaussian smoothing, as detailed in Section 2.1.2. This paper uses $\sigma = 20$ for smoothing at the wholesale market level. By leaving all system parameters unchanged, the total system cost function is reduced to an implicit function of the aggregated prosumer and consumer load RL_{total}; see Equation (9).

$$C_{sys}^{total}(\cdot) \rightarrow C_{sys}^{total}(RL_{total}) \tag{9}$$

Subsequently, the annualized total system costs are minimized, as shown in Equation (10).

$$\min_{x \in \mathbb{R}_+^n} C_{sys}^{total}(RL_{total}) = \min_{x \in \mathbb{R}_+^n} (c^T x(RL_{total}) + C_{NW}^{total}) = \min_{x \in \mathbb{R}_+^n} c^T x(RL_{total}) \tag{10}$$

The system model realistically depicts several constraints as characteristic features of the electricity market. The most important of these are load coverage, system adequacy, and the depiction of RES investment paths. A detailed discussion of these features is shown in [2].

- **Load coverage**: This is the fundamental model restriction, guaranteeing that total demand is covered by production for every model hour. Hereby, demand can be covered either directly through power plant production (including variable RES), or indirectly, via discharging of storages (including distributed battery storages). Moreover, electricity transmission between regions is a third contribution to fulfill this restriction;
- **System adequacy:** This restriction guarantees the security of supply within every model hour in that the total capacity of dispatchable power plants, weighted by their respective operational reliabilities $\in (0,1)$, matches the maximum electric load in the model year. The operational reliabilities for variable RES are assumed to be zero in this paper;
- **Investment paths**: RES investment paths are provided as model-exogenous input. The rationale behind this restriction is that in this study we are not primarily interested in a global optimization of the energy system including RES investment capacities, but rather analyze different operational modes of distributed flexibilities (batteries) under a given power plant structure.

The number of households (N = 40 million) and the annual electricity demand (500 TWh) are loosely informed by the German market size. The power plant structure is dominated by RES: 180 GW PV, 60 GW wind offshore, and 100 GW wind onshore, loosely based on the 2050 values of a 95% decarbonization scenario; see [2] for further details.

2.2. Operation Mode 2

The principal analysis steps for operation mode 2 are the same as presented above for operation mode 1. However, this time the actual battery operation mode is adjusted to reduce the peak-coincident network utilization. At this point, the battery operation is formulated as a linear optimization problem, with the prosumer SC as an objective function being maximized, as shown in Equation (11).

$$SC = D_{Pros} - \sum_n gs(t_n) \rightarrow \max \tag{11}$$

For the model, the technical characteristics of the battery are represented as linear restrictions, congruent to the formulation in Appendix A with variable definition and parameter setting provided by Tables 1 and 3; see Algorithm 1.

Table 3. Summary of the used variables and parameters for prosumer battery storage operation (battery operation mode 2).

	Description	Unit	Value	Source
Variables				
$p_{Batt}(t_n)$	Momentary power supply from battery	[kW]	*Output*	-
$s_{Batt}(t_n)$	Momentary battery charging	[kW]	*Output*	-
Parameters				
$d_{pros}(t_n)$	Momentary prosumer electricity demand	[kW]	Given load profile	[22,23]
$p_{PV}(t_n)$	Momentary PV production	[kW]	From PV profile	[23]
$P_{PV,\text{peak}}$	Peak PV capacity	[kW]	6	Assumption
η_s	Battery charging efficiency	[%]	100	Assumption
η_p	Battery discharging efficiency	[%]	100	Assumption

Algorithm 1 Battery operation mode 2.

```
for $b \in$ range($b_{init}$; 0; step-size: $\epsilon$) do
  Try
  Objective function
  $SC = \text{DemandElec} - \sum_n gs(t_n) \rightarrow \max$
  Restrictions
  R1: Load coverage:
  $d_{Pros}(t_n) = p_{PV}(t_n) + p_{Batt}(t_n) - s_{Batt}(t_n) + gs(t_n) - fi(t_n) \quad \forall t_n \in T$
  R2: Capacity constraints:
  $p_{PV}(t_n) = \text{FLH} \cdot \text{profile}(t_n) \cdot P_{PV,\text{peak}} \cdot \text{TimeRes}^{-1} \quad \forall t_n \in T$
  $p_{Batt} \leq \text{BattPower} \quad \forall t_n \in T$
  R3: Storage constraints:
  $s_{Batt}(t_n) \leq \text{BattCharging} \quad \forall t_n \in T$
  $\text{BattFillLevel}(t_{n+1}) = \text{BattFillLevel}(t_n) + (s_{Batt}(t_n) \cdot \eta_s - p_{Batt}(t_n) \cdot \eta_p) \cdot \text{TimeRes} \quad \forall t_n \in T$
  $0 \leq \text{BattFillLevel}(t_n) \leq \text{BattContent} \quad \forall t_n \in T$
  R4: Peak-coincident network capacity constraint:
  $gs(t_n) \cdot \rho + d_{Cons}(t_n) \cdot (1 - \rho) \leq b \quad \forall t_n \in T$
  $fi(t_n) \cdot \rho \leq b \quad \forall t_n \in T$
end for
```

At this point, one determines the lowest value possible for an upper boundary b that restricts the residual load at the distribution network node while still leaving the optimization problem solvable. This upper bound can be found using interval nesting. In turn, the corresponding resulting prosumer residual load serves as input for the subsequent analyses of network utilization and system costs, as described in detail for operation mode 1. By construction, battery operation mode 2 maximizes the prosumer SC while reducing the peak-coincident network capacity utilization as much as possible. One could thus argue that this operation mode represents an improvement to the prosumer heuristic of operation mode 1, which accounts for a prosumer response to a regulatory framework which is based on peak-coincident network capacity charges.

2.3. Operation Mode 3

Next, operation mode 3 differs from the other operation modes in that this time, the prosumer battery serves as a full flexibility option in the wholesale market, reacting to the real-time wholesale market price signal. For operation modes 1 and 2 we determine the aggregated residual load of the prosumer and consumer households as system model-exogenous time series. For operation mode 3, instead, we begin the analysis with the minimization of total system costs, leaving the battery operation as a degree of freedom for the system. This way, the battery operation and the corresponding prosumer residual load are model endogenous results of the system optimization. Next, the distribution network capacity utilization is determined in a similar way to that described in Section 2.1.2. Moving from the wholesale market level to the distribution network level, we need to convert the residual load profiles of prosumers and consumers into sharper versions. This is virtually the reverse operation to the Gaussian smoothing, for which Equation (5) is applied. After this analysis step, we can evaluate the peak-coincident network capacity utilization as well as prosumer and consumer FCOE.

2.4. Consideration of Widespread e-Mobility

To understand the effects of widespread e-mobility, we perform the analyses as described in Sections 2.1–2.3; however, these analyses are performed under the consideration of additional electric load originating from widespread e-mobility. To do so, the original electric load time series is added by an electric charging time series, as provided in [28]. As e-mobility constitutes both a source of electricity demand and flexibility, a smart charging control is assumed. In other words, the applied charging time series itself is an optimization result under consideration of price incentives and greenhouse gas (GHG) emission targets. The additional annual electricity demand for e-mobility is assumed to be 2000 kWh per household. The maximum momentary charging capacity (quarter hour average) is assumed to be 3.7 kW per household. The parametric assumptions are based on [28]. The assumed maximum charging capacity is based on a typical wallbox for home use; however, higher charging capacities could well become standard in the future. We would like to point out that we do not intend to make a forecast for future e-mobility charging needs, but would rather like to show the general effects resulting from increasing sector integration. Note also that the additional electric load could be representative of all kinds of additional electricity demand resulting from increasing sector integration, i.e., electrification of heat and mobility sectors.

3. Results

3.1. Global Perspective: System Effects

As illustrated by Figure 4, the total system costs are highest for operation mode 1 (chronological charging of battery) and lowest for operation mode 3 (market-beneficial battery operation) (The following results section is partly taken from [1] and significantly complemented by additional results, including a variation analysis of the prosumer penetration ratio and consideration of widespread e-mobility). The relative system cost delta is 0.8%, corresponding to ca. 400 MN EUR p.a. with a system cost base of roughly 50 BN EUR p.a. The specific values refer to a setting of 50% prosumer penetration ratio; the general tendencies, however, remain unaltered for all other prosumer penetration ratios. The system cost effect is based on the fact that a flexible battery operation (as in operation mode 3) enables an overall better RES integration than in the case of a predetermined battery operation, as in operation mode 1. This fact leads to overall lower fuel and CO_2 costs in the system. For a more detailed discussion, one may read [2].

Interestingly, battery operation mode 2 leads to nearly the same total system cost optimum compared to battery operation mode 1 for all three analyzed prosumer penetration ratios (25%, 50%, 75%). This indicates that the rationale behind battery operation mode 2 to release stress on the distribution grid is not per se congruent to a market-beneficial battery operation. Additionally, the different battery operation modes show even stronger differences in their CO_2 emissions. The underlying cause is the same as that of the total system cost decrease: better overall RES integration, especially for operation mode 3, leading to a reduction of the unit commitment of dispatchable, CO_2-intensive power plants (gas turbines). In case that the overall GHG emissions are limited by a fixed Emissions Trading System (ETS) cap, there would not be an overall CO_2 emissions difference between the three battery operation modes. Instead, battery operation mode 3 could achieve the same CO_2 targets with less overall RES capacity installed compared to operation modes 1 and 2. A summary of the results at the system level including all three considered prosumer penetration ratios is provided by Table 4.

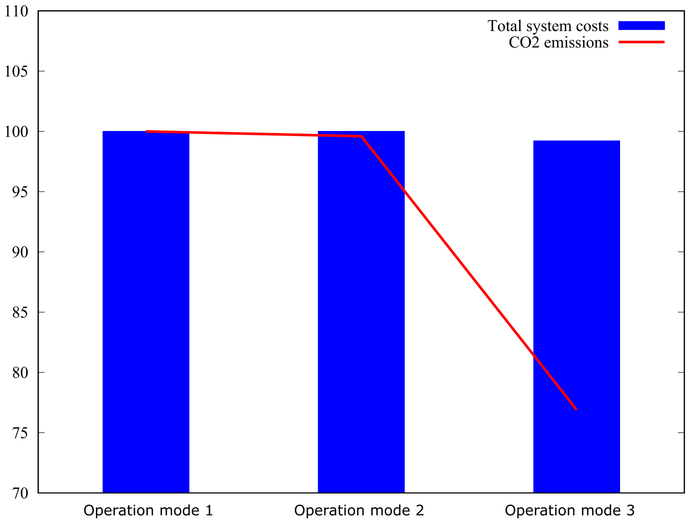


Figure 4. Annualized total system costs and CO_2 emissions, normalized in % of respective values for battery operation mode 1, by battery operation mode, for 50% prosumer penetration ratio.

Table 4. Summary of system effects.

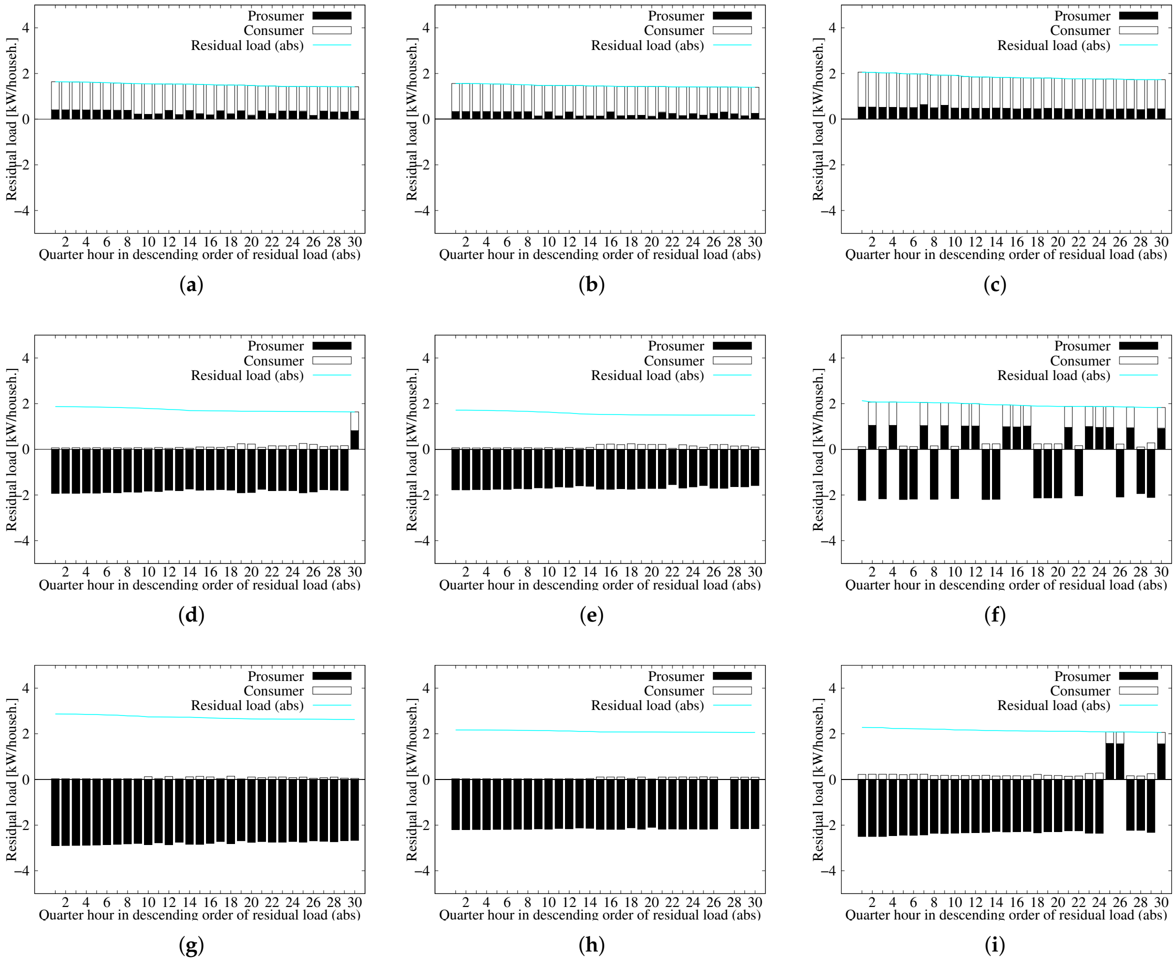
		Op. Mode 1 *Max SC*	**Op. Mode 2** *Grid-Oriented*	**Op. Mode 3** *Market-Oriented*
25% prosumer penetration ratio				
Total system costs	[MN EUR/a] [% of op. mode 1]	45,645 100.0%	45,653 100.0%	45,345 99.3%
Annual CO_2 emissions	[million t] [% of op. mode 1]	5016 100.0%	5015 100.0%	4264 85.0%
50% prosumer penetration ratio				
Total system costs	[MN EUR/a] [% of op. mode 1]	47,204 100.0%	47,202 100.0%	46,808 99.2%
Annual CO_2 emissions	[million t] [% of op. mode 1]	3025 100.0%	3013 99.6%	2326 76.9%
75% prosumer penetration ratio				
Total system costs	[MN EUR/a] [% of op. mode 1]	49,429 100.0%	49,401 99.9%	49,196 99.5%
Annual CO_2 emissions	[million t] [% of op. mode 1]	2308 100.0%	2290 99.2%	1791 77.6%

3.2. Local Perspective: Network Capacity Utilization

To evaluate the effects at the distribution network level, this study quantifies the situations of maximum residual load on the distribution network node for each of the battery operation modes 1, 2, and 3 and three different prosumer penetration ratios (25%, 50%, 75%) as indicators for the thermal stress on the network node; see Figure 5. The figure shows the top 30 highest residual load peaks in descending order. For low (25%) and medium (50%) prosumer share ("low", "medium", and "high" refer to our scenario framework and are by no means value statements with regards to the expected future prosumer penetration ratios), the thermal stress situations are generally induced by load peaks, with the exception of the market-oriented battery operation mode 3 at 50% prosumer share. In this case, load and feed-in peaks contribute in equal parts to the network stress. For high prosumer shares (75%), the network stress is dominated by feed-in peaks, irrespective of the actual battery operation mode, even though for battery operation mode 3 at least 10% of the 30 highest residual load peaks is attributed to load peaks. By construction, the network-oriented battery operation mode 2 leads to the lowest maximum residual load peaks for all three prosumer shares. For low prosumer shares (25%), the prosumer-centric battery operation mode 1 leads to lower residual load peaks than battery operation mode 3, whereas for high prosumer shares (75%), battery operation mode 1 results in the overall highest residual load peaks. Compared to a grid-oriented battery operation, for a 75% prosumer penetration ratio, battery operation mode 1 results in a 29% higher capacity utilization on the top 30 average (2.72 vs. 2.11 kW per household) and in a 32% higher capacity utilization for the single highest residual load peak in the year (2.87 vs. 2.17 kW per household). This becomes more obvious when looking at Figure 6, which shows the annual residual load duration curves (cyan) and the corresponding momentary battery charging (black) for a 75% prosumer penetration ratio. For battery operation mode 1, one can clearly see that the situations of highest residual loads (which are dominated by feed-in peaks) occur in combination with zero battery charging. These situations typically correspond to feed-in peaks around noon, when the prosumer battery is already fully charged according to the chronological charging heuristic, and prosumer load is low. In contrast, for the network-oriented battery operation mode 2, there is a more balanced battery charging throughout the day, which helps compensate for the highest feed-in peaks, at least to some extent. A summary of results is provided by Table 5.

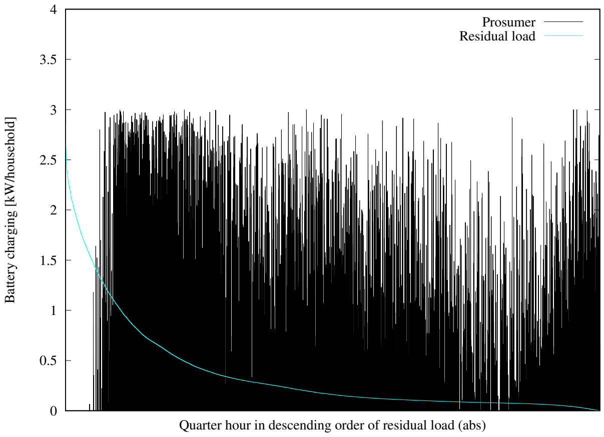
Table 5. Summary of grid-level effects.

		Op. Mode 1 *Max SC*	**Op. Mode 2** *Grid-Oriented*	**Op. Mode 3** *Market-Oriented*
25% prosumer penetration ratio				
Maximum peak coincident residual load	[kW]	1.64	1.56	2.05
Average of top 30 residual load peaks	[kW]	1.52	1.46	1.85
. . . thereof grid load share	[%]	0%	0%	0%
. . . thereof feed-in share	[%]	100%	100%	100%
50% prosumer penetration ratio				
Maximum peak coincident residual load	[kW]	1.87	1.71	2.13
Average of top-30 residual load peaks	[kW]	1.73	1.57	1.95
. . . thereof grid load share	[%]	97%	100%	50%
. . . thereof feed-in share	[%]	3%	0%	50%
75% prosumer penetration ratio				
Maximum peak coincident residual load	[kW]	2.87	2.17	2.28
Average of top-30 residual load peaks	[kW]	2.72	2.11	2.15
. . . thereof grid load share	[%]	100%	100%	90%
. . . thereof feed-in share	[%]	0%	0%	10%



(**a**) (**b**) (**c**) (**d**) (**e**) (**f**) (**g**) (**h**) (**i**)

Figure 5. Residual loads at node, per household [kW] and in descending order of the absolute value of the residual load. All figures are for a distribution network of $n = 49$ households, i.e., $\sigma = 7$. (**a**) Battery mode 1 at a 25% pros. penetration; (**b**) Battery mode 2 at a 25% pros. penetration; (**c**) Battery mode 3 at a 25% pros. penetration; (**d**) Battery mode 1 at a 50% pros. penetration; (**e**) Battery mode 2 at a 50% pros. penetration; (**f**) Battery mode 3 at a 50% pros. penetration; (**g**) Battery mode 1 at a 75% pros. penetration; (**h**) Battery mode 2 at a 75% pros. penetration; (**i**) Battery mode 3 at a 75% pros. penetration.



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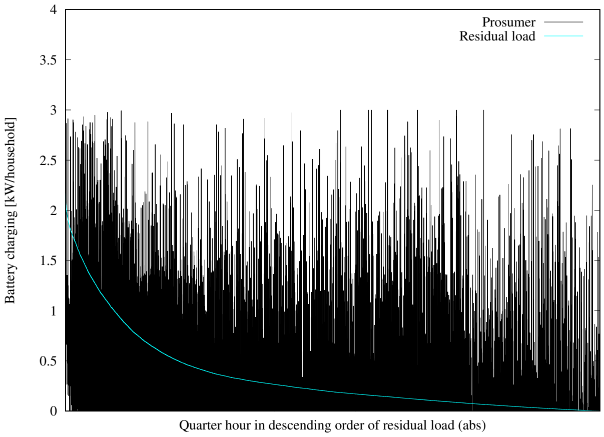

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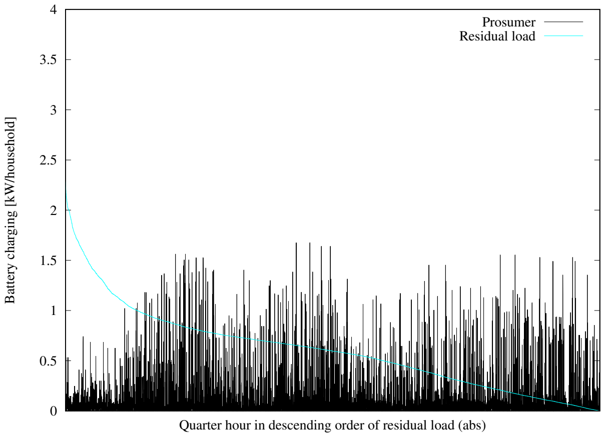


(**c**)

Figure 6. Annual residual load duration curves (absolute values; cyan) and battery charging (black); by battery operation mode); for 75% prosumer penetration ratio. (**a**) Battery operation mode 1; (**b**) Battery operation mode 2; (**c**) Battery operation mode 3.

3.3. Individual Perspective: End Customer Effects

The analysis of prosumer and consumer FCOE helps identify which battery operation mode is favorable to prosumers and consumers, respectively, distinguishing two different network cost allocation schemes. Figure 7 depicts the normalized prosumer and consumer FCOE (normalization base: 800 EUR p.a.) for the three battery operation modes and three different prosumer penetration ratios (25%, 50%, 75%). On the left side of each subfigure (a–i), the FCOE are evaluated for volumetric network charges (*VNC*). On the right side of the subfigure (a–i), the FCOE are evaluated for peak capacity charges (*CNC*). Each figure also shows which part of the FCOE is attributed to network charges (violet) and which part is attributed to investment and market costs (green). The figure depicts a couple of interesting results: first, investments in distributed PV and battery systems are economically viable both under volumetric and peak capacity network charges, in principle, i.e., prosumer FCOE are lower than consumer FCOE. This is generally true for all battery operating modes with the exception of operating mode 3 in combination with peak capacity charges at medium (50%) and high (75%) prosumer penetration ratios. Second, one can clearly see that peak capacity charges generally tend to reduce the FCOE gap between prosumers and consumers (and even reverse it for operation mode 3 at medium and high prosumer penetration ratios). The essentially larger gaps between prosumer and consumer FCOE under volumetric network charges are a direct result of the fact that volumetric network charges enable prosumers to more strongly reduce their shares of refinancing grid infrastructure and operation costs through high SC; see also other studies such as [7,12]. However, high SC does not per se reduce network charges for prosumers in case of peak capacity charges, as charging is based on peak capacity utilization rather than actual energy volume withdrawn from the public network. Third, one can see that from a prosumer perspective, the market-beneficial battery operation (operation mode 3) is neither favorable for volumetric nor peak capacity network charges, i.e., prosumer FCOE are highest for battery operation mode 3, independent of the network cost allocation scheme and the prosumer penetration ratio. This is a direct consequence of the generally significantly lower achievable prosumer SC ratios in case of a market-oriented battery operation. In this study, the SC ratios decrease from 51% for battery operation modes 1 and 2 to 29–35% for battery operation mode 3. This demonstrates that further adjustments of the regulatory framework are needed to incentivize market-beneficial battery operation. As a consistency check, one can see that for peak capacity charges, the network-beneficial battery (operation mode 2) is favorable to the prosumer. Elsewhere, for volumetric network charges, chronological charging of the battery (operation mode 1) guarantees the lowest FCOE for the prosumer. A summary of results is provided by Tables 6 and 7.

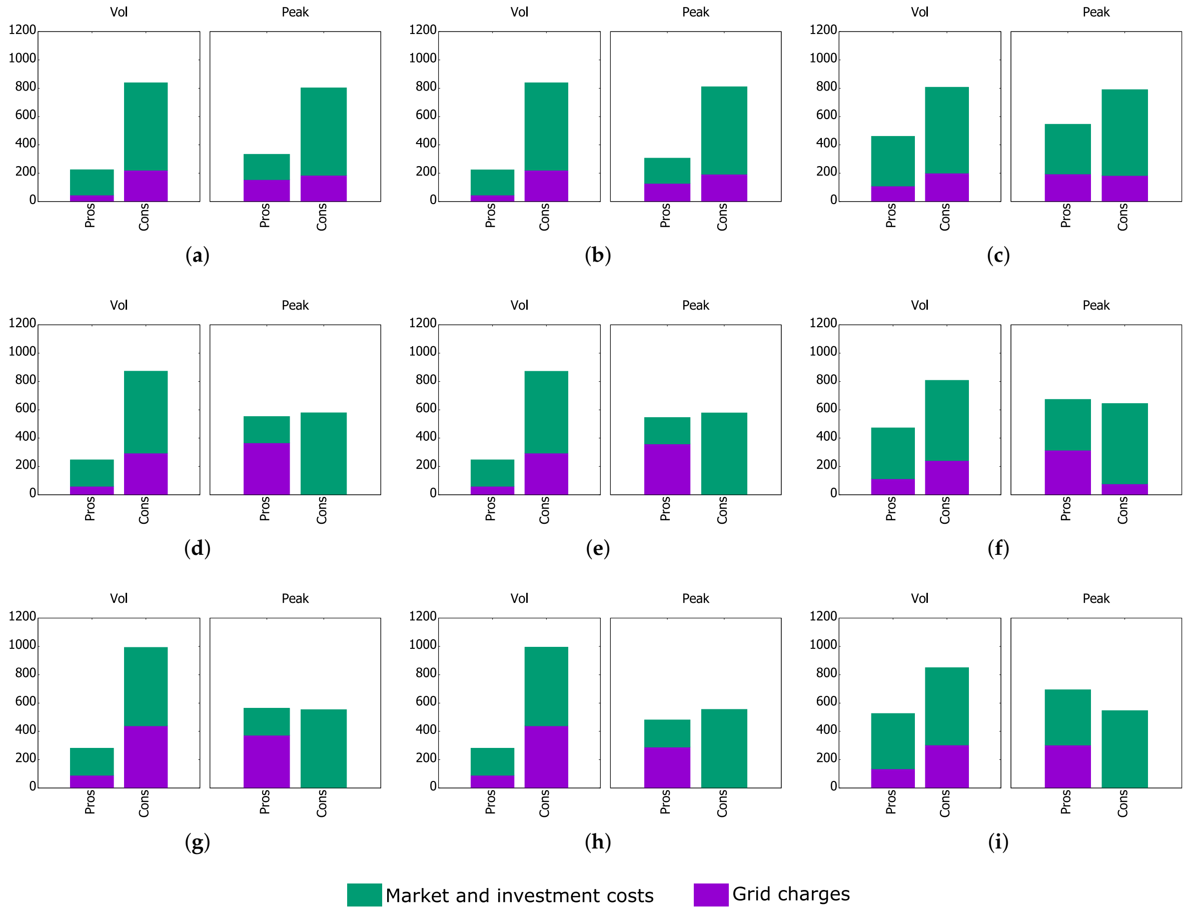
As illustrated in Figure 7, in the case of peak-coincident capacity charges, only prosumers pay network charges for medium (50%) and high (75%) prosumer penetration ratios. This is a direct consequence of the corresponding network utilization, which is (nearly) fully induced by prosumer feed-in peaks; see Figure 5. Consecutively, the specific *CNC* times the number of prosuming households excels the needed network refinancing sum; therefore, no additional fixed charge per customer is required, which would have been paid by prosumers and consumers. Consequently, in these cases, only prosumers pay network charges whereas consumers are entirely disburdened.

Table 6. Summary of end customer effects for volumetric grid charges.

VNC		**Op. Mode 1** *Max SC*	**Op. Mode 2** *Grid-Oriented*	**Op. Mode 3** *Market-Oriented*
25% prosumer penetration ratio				
FCOE prosumer	[EUR/a]	225	225	460
. . . thereof grid charges	[EUR/a]	45	45	109
FCOE consumer	[EUR/a]	839	839	807
. . . thereof grid charges	[EUR/a]	221	221	200
FCOE consumer/FCOE prosumer	[%]	373%	373%	175%
50% prosumer penetration ratio				
FCOE prosumer	[EUR/a]	247	247	474
. . . thereof grid charges	[EUR/a]	60	60	113
FCOE consumer	[EUR/a]	873	872	808
. . . thereof grid charges	[EUR/a]	294	294	241
FCOE consumer/FCOE prosumer	[%]	354%	353%	171%
75% prosumer penetration ratio				
FCOE prosumer	[EUR/a]	281	281	526
. . . thereof grid charges	[EUR/a]	90	90	135
FCOE consumer	[EUR/a]	993	995	850
. . . thereof grid charges	[EUR/a]	439	439	303
FCOE consumer/FCOE prosumer	[%]	353%	354%	161%

Table 7. Summary of end customer effects for peak capacity charges.

CNC		**Op. Mode 1** *Max SC*	**Op. Mode 2** *Grid-Oriented*	**Op. Mode 3** *Market-Oriented*
25% prosumer penetration ratio				
FCOE prosumer	[EUR/a]	334	308	546
. . . thereof grid charges	[EUR/a]	154	128	194
FCOE consumer	[EUR/a]	802	811	789
. . . thereof grid charges	[EUR/a]	185	193	183
FCOE consumer/FCOE prosumer	[%]	240%	263%	145%
50% prosumer penetration ratio				
FCOE prosumer	[EUR/a]	553	546	674
. . . thereof grid charges	[EUR/a]	366	359	314
FCOE consumer	[EUR/a]	579	578	643
. . . thereof grid charges	[EUR/a]	0	0	77
FCOE consumer/FCOE prosumer	[%]	105%	106%	95%
75% prosumer penetration ratio				
FCOE prosumer	[EUR/a]	563	481	694
. . . thereof grid charges	[EUR/a]	372	290	303
FCOE consumer	[EUR/a]	554	555	547
. . . thereof grid charges	[EUR/a]	0	0	0
FCOE consumer/FCOE prosumer	[%]	98%	116%	79%



(**a**) (**b**) (**c**) (**d**) (**e**) (**f**) (**g**) (**h**) (**i**)

Figure 7. FCOEs for prosuming and consuming households [EUR/a] for different battery operation modes (1/2/3), network cost allocation schemes (vol/peak), and prosumer penetration ratios (25%, 50%, 75%). (**a**) Battery mode 1 at a 25% pros. penetration; (**b**) Battery mode 2 at a 25% pros. penetration; (**c**) Battery mode 3 at a 25% pros. penetration; (**d**) Battery mode 1 at a 50% pros. penetration; (**e**) Battery mode 2 at a 50% pros. penetration; (**f**) Battery mode 3 at a 50% pros. penetration; (**g**) Battery mode 1 at a 75% pros. penetration; (**h**) Battery mode 2 at a 75% pros. penetration; (**i**) Battery mode 3 at a 75% pros. penetration.

3.4. Effects of Widespread e-Mobility

In this subsection, we present the results at the system, network, and individual household levels under consideration of widespread e-mobility. Figure 8, which shows total system costs and CO_2 emissions as a function of the battery operation mode, displays a very similar pattern as in the case without e-mobility (Figure 4). Market-oriented battery operation results both in the lowest total system costs and lowest overall CO_2 emissions. However, widespread e-mobility reduces the relative CO_2 reduction for battery operation mode 3, compared to a setting without e-mobility (10.5% vs. 23.1% for a 50% prosumer penetration ratio). This is a direct consequence of an overall increased electricity demand resulting in better RES integration options for all three battery operation modes, and consequently reducing the deltas between battery operation modes 1, 2 and battery operation mode 3.

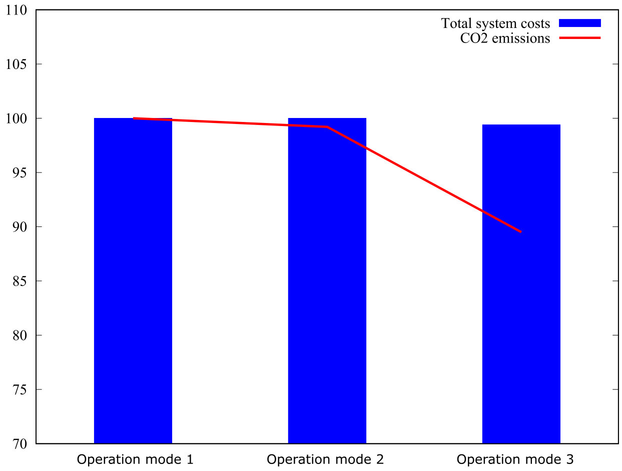
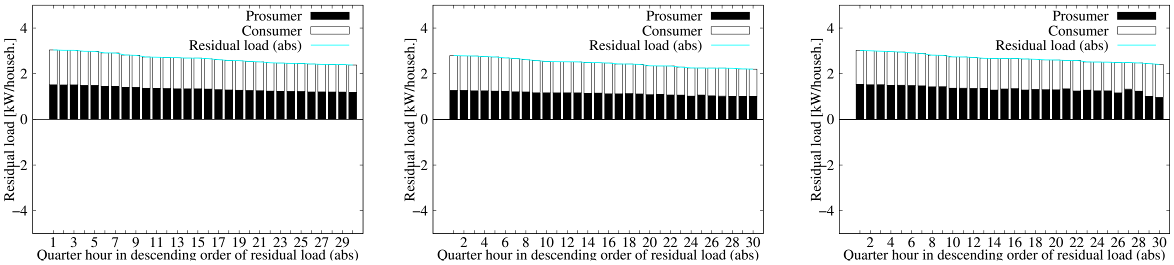


Figure 8. Annualized total system costs and CO_2 emissions, normalized in % of respective values for battery operation mode 1 by battery operation mode for a 50% prosumer penetration ratio under consideration of widespread e-mobility.

In case of widespread e-mobility, the situations of maximum network capacity utilization are load-driven, irrespective of the battery operation mode; see Figure 9. This is in contrast to Figure 5, where the corresponding situations are induced by feed-in peaks in a setting without e-mobility for medium and high prosumer shares. Moreover, the absolute value of the maximum residual load peaks increases significantly under consideration of e-mobility, from around 2 kW per household to around 3 kW per household, corresponding to a relative increase of approximately 50%. In view of the maximum feed-in peaks in Figure 5, which are lower than 3 kW per household for all three considered prosumer penetration ratios, one can conclude that with widespread e-mobility, the thermal stress will be predominantly induced by load peaks, irrespective of the actual prosumer share. As in the setting without e-mobility, Figure 9 demonstrates that battery operation mode 2 leads to the overall lowest maximum network capacity utilization (2.79 kW vs. 3.04 kW for battery operation mode 1 and 3.02 kW for battery operation mode 2). This corresponds to a maximum peak load reduction of 8% compared to battery operation mode 1, which matches the relative reduction for a setting without e-mobility (1.71 kW vs. 1.87 kW); see Table 5. This demonstrates that a grid-oriented battery operation can, in principle, efficiently release the distribution network both in a feed-in and a load-dominated setting.



(**a**) (**b**) (**c**)

Figure 9. Residual loads at the node, per household [kW] and in descending order of the absolute value of the residual load. All figures are for a distribution network of $n = 49$ households, i.e., $\sigma = 7$. For a 50% prosumer penetration ratio under consideration of widespread e-mobility. (**a**) Battery mode 1, with e-mobility; (**b**) Battery mode 2, with e-mobility; (**c**) Battery mode 3, with e-mobility.

Figure 10 further reveals the effect of widespread e-mobility at the distribution network level by depicting the maximum residual load peak on the network node within a year for each hour of the day; see Equation (12). Here, h_i represents a selected hour h of the day.

$$RL^{max}_{Node}(h_i) = \max_{t\in T,\, h=h_i}(RL_{Node}(t)) \quad \forall i \in 0,\ldots,23 \tag{12}$$

For a setting without e-mobility, the situations of maximum thermal stress are induced by feed-in peaks around noon (orange, first line of Figure 10a–c, whereas under consideration of e-mobility, the situations of maximum thermal stress are induced by load peaks in the night (blue, second line of Figure 10d–f, when the electric vehicles are charged. Feed-in peaks still occur during noon times but play a minor role compared to the load peaks. In this context it is questionable whether general PV peak shaving, which is part of some of today's regulatory frameworks, will remain a reasonable instrument for distribution network release in the future.

Figure 11 depicts prosumer and consumer FCOE under consideration of widespread e-mobility. In principle, this figure resembles the situation depicted in Figure 7; however, the gaps between prosumer and consumer FCOE tend to be even larger in the case of widespread e-mobility. This is the expected result, as with e-mobility, the annual electricity demand per household increases and so do the electricity supply costs. This primarily affects the consuming households, who do not have cost mitigation options through SC. Meanwhile, prosumers can even increase their SC ratios (59% for battery operation modes 1 and 2 and 46% for battery operation mode 3). Even though one can clearly see that capacity-based network charges mitigate the FCOE gaps even in case of widespread e-mobility, they cannot be sufficient in order to eliminate these inequalities entirely. This, again, highlights that further regulatory instruments would be needed in order to share the burdens between different stakeholder groups, such as prosumers and consumers, more fairly.

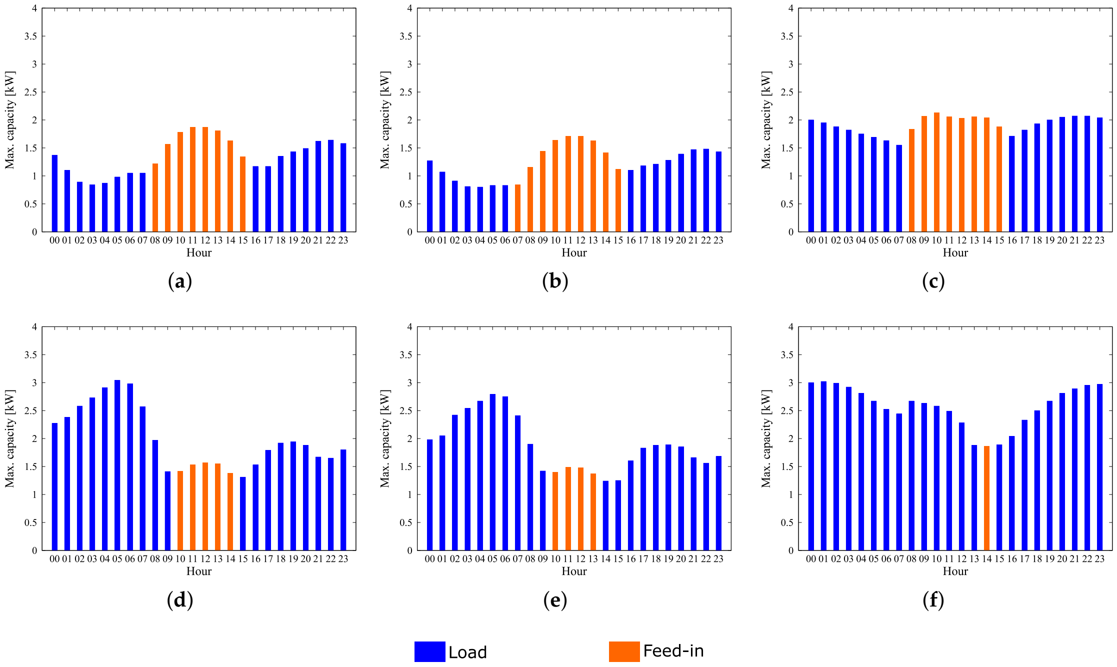


Figure 10. Maximum residual load per hour in a year, per household [kW]. All figures for a distribution network of $n = 49$ households, i.e., $\sigma = 7$. For a 50% prosumer penetration ratio, second line under consideration of widespread e-mobility. (**a**) Battery mode 1, without e-mobility; (**b**) Battery mode 2, without e-mobility; (**c**) Battery mode 3, without e-mobility; (**d**) Battery mode 1, with e-mobility; (**e**) Battery mode 2, with e-mobility; (**f**) Battery mode 3, with e-mobility.

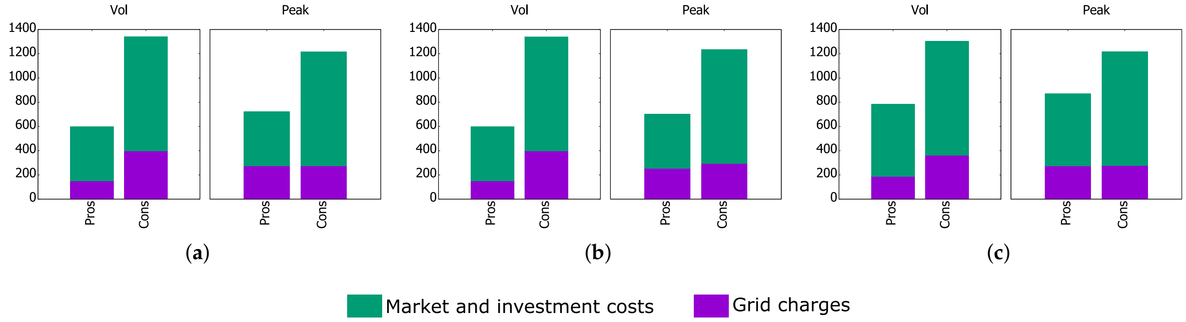


Figure 11. FCOEs for prosuming and consuming households [EUR/a] for different battery operation modes (1/2/3), network cost allocation schemes (vol/peak), and 50% prosumer penetration ratio under consideration of widespread e-mobility. (**a**) Battery mode 1 with e-mobility; (**b**) Battery mode 2 with e-mobility; (**c**) Battery mode 3 with e-mobility.

4. Discussion

Overall, this manuscript evaluates the impact of prosumer behavior at the individual level (electricity bill), local level (distribution network stress), and the system level (total system costs) (The following discussion section is taken from [1] and slightly adapted and complemented). Volumetric network charges tend to favor battery operation modes that are neither grid- nor market-oriented. Such battery operation modes can result in significantly higher thermal stress on the distribution network nodes. Moreover, these modes can cause overall higher system costs and CO_2 emissions due to an overall reduced RES integration capacity. Moreover, volumetric network charges can amplify the gap between prosumer and consumer household electricity bills. These inequalities could be mitigated by capacity-based network charges, which could help redistribute the burdens that originate form refinancing network operation and infrastructure costs between prosumers and consumers. Moreover, peak capacity charges could constitute an incentive for different battery operation modes. Besides reducing potentially significant inequalities between prosumer and consumer electricity bills, such grid-oriented battery operation modes could release the distribution network for settings of predominantly negative residual load peaks as well as for settings of predominantly positive residual load peaks. However, grid-oriented battery operation modes do not, per se, result in corresponding positive market effects. On the contrary, this paper suggests that there are conflicting objectives between network-oriented and market-oriented battery operation. In this study, market-oriented battery operation displays optimal RES integration, resulting in the lowest system costs and CO_2 emissions. Explicit consideration of widespread e-mobility results in the same basic picture, which at the same time is an important indication of the stability of the results in view of parametric uncertainties (profile effects). Individual inequality effects, in particular, could be even increased by e-mobility as the advantage of prosumer SC is leveraged through increasing electrification of further end uses. We would like to emphasize that the analysis is in parts highly stylized and exhibits several limitations that require further research. Most prominently, a more detailed disaggregation of household groups and corresponding profiles, as well as explicit load flow calculations, could be performed in further research.

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Abbreviations

The following abbreviations are used in this manuscript:

CNC	(Peak-coincident) network capacity charges
ETS	Emissions Trading System
FCOE	Full costs of electricity
GHG	Greenhouse gas
LCOE	Levelized cost of electricity
PV	Photovoltaic
RES	Renewable energy sources
SC	Self-consumption
VNC	Volumetric network charges

Appendix A

Algorithm A1. Battery operation mode 1.

```
for $i \in$ range(0; 35,040) do
  if $\text{ResLoad} \geq 0$ then
    $\text{FeedIn} = 0$
    if $\text{ResLoad} \leq \text{Batt Power}$ then
      if $\text{BattFillLevel} - \text{ResLoad} \times \text{TimeRes} \geq 0$ then
        $\text{GridSupply} = 0$
        $\text{BattFillLevel} = \text{BattFillLevel} - \text{ResLoad} \times \text{TimeRes}$
      else
        $\text{GridSupply} = (\text{ResLoad} \times \text{TimeRes} - \text{BattFillLevel})/\text{TimeRes}$
        $\text{BattFillLevel} = 0$
      end if
    else
      if $\text{BattFillLevel} - \text{BattPower} \times \text{TimeRes} \geq 0$ then
        $\text{GridSupply} = \text{ResLoad} - \text{BattPower}$
        $\text{BattFillLevel} = \text{BattFillLevel} - \text{BattPower} \times \text{TimeRes}$
      else
        $\text{GridSuppy} = (\text{ResLoad} \times \text{TimeRes} - \text{FillLevelBatt})/\text{TimeRes})$
        $\text{BattFillLevel} = 0$
      end if
    end if
  else
    $\text{GridSupply} = 0$
    if $\text{ResLoad} \leq \text{BattCharging}$ then
      if $\text{BattFillLevel} - \text{ResLoad} \times \text{TimeRes} \leq \text{BattContent}$ then
        $\text{FeedIn} = 0$
        $\text{BattFillLevel} = \text{BattFillLevel} - \text{ResLoad} \times \text{TimeRes}$
      else
        $\text{FeedIn} = (\text{BattFillLevel} - \text{ResLoad} \times \text{TimeRes} - \text{BattContent})/\text{TimeRes}$
        $\text{BattFillLevel} = \text{BattContent}$
      end if
    else
      if $\text{BattFillLevel} + \text{BattCharging} \times \text{TimeRes} \leq \text{BattContent}$ then
        $\text{FeedIn} = \text{ResLoad} - \text{BattCharging}$
        $\text{BattFillLevel} = \text{BattFillLevel} + \text{BattCharging} \times \text{TimeRes}$
      else
        $\text{FeedIn} = (\text{FillLevelBatt} - \text{ResLoad} \times \text{TimeRes} - \text{BattContent})/\text{TimeRes}$
        $\text{BattFillLevel} = \text{BattContent}$
      end if
    end if
  end if
end for
```

Appendix B

We demonstrate that our approach is in (asymptotical) accordance with the theoretical functional n-dependency. The core idea is to generate n profiles from a sharp input profile $p_{sharp}(t)$ by means of shifting the residual load profile values at every time step to the left and right (in temporal dimension), with shift probabilities weighted by a Gaussian normal distribution; see Equation (4). Mathematically, this means convolving the original, sharp profile with a Gaussian function.

Now we transfer this formulation to the discrete case and switch from the continuous time parameter t to discrete time steps m, applying $\sigma = \sqrt{n}$. For given σ and m_0, we shift from $m_0 - 6\sigma$ until $m_0 + 6\sigma$. Moreover, we apply the series expansion of the exponential function, leading to Equation (A1).

$$\begin{aligned} p^n_{smooth}(m_0) &= \sum_{m=-6\sigma}^{6\sigma} p_{sharp}(m+m_0) \cdot \frac{1}{\sqrt{2\pi\sigma^2}} \cdot e^{-\frac{m^2}{2\sigma^2}} \\ &= \frac{1}{\sqrt{2\pi n}} \sum_{m=-6\sqrt{n}}^{6\sqrt{n}} p_{sharp}(m+m_0) \cdot \left(1 - \frac{m^2}{2n} + \mathcal{O}\left(\frac{1}{n^2}\right)\right) \\ &= \frac{1}{\sqrt{n}} \cdot \left(c_1(m_0) + c_2(m_0)\frac{1}{n} + \mathcal{O}\left(\frac{1}{n^2}\right)\right) \end{aligned} \tag{A1}$$

Finally, assume that m_0 represents the x-coordinate of the extremum of the smoothed sum profile. Note, however, that m_0 actually is a function of n. For the applied profiles in this study, however, we can check that m_0 indeed remains relatively constant for $n >> 1$. Hence

$$g(n) \sim p^n_{smooth}(m_0) \sim \frac{1}{\sqrt{n}} \tag{A2}$$

Note that for the trivial calse $n = 1$ the simultaneity factor is 1 (as it should be). For any larger n, the simultaneity factor decreases with $\frac{1}{\sqrt{n}}$ towards its limit g_∞; see Equation (A3).

$$\lim_{n\to\infty} g(n) = g_\infty \tag{A3}$$

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6 Conclusions

The analyses of the present work show that the large-scale emergence of prosumers affects the energy system at different scales, ranging from effects for the individual household and the local distribution network node, to effects for the wholesale market and wholesale prices. On the one hand, the magnitude of these effects simply depends on the number of prosumer households – and this number is likely to increase dramatically, both worldwide and in Germany, in the upcoming years. For Germany, this is also a direct consequence of respective legislative stipulations such as the solar duty for new residential buildings, which has already been implemented in a few federal states, e.g., Berlin, Hamburg, and Baden-Württemberg.[13] On the other hand, prosumers' actual behavior with regard to investing in and operating their distributed energy production and storage systems plays a decisive role, which is largely determined by the regulatory framework. The analyses of the present work suggest that the existing regulatory framework is inadequately prepared to integrate prosumers in a system-beneficial manner within an ever-increasing decentralization of the energy system. In this section, we discuss the main conclusions alongside the different scales of the energy system, including providing answers to the specific questions H1, H2, N1, N2, S1, and S2 from Section 2.2. The respective passages in the text are marked by appending the corresponding abbreviations of the questions in parentheses. To begin, the effects for individual households are discussed.

6.1 Distributional effects from the emergence of prosumers

The findings on distributional effects from the emergence of prosumers are framed by empirical figures for the whole of Germany for 2000–2021, as presented in Paper A, Section 3. On the basis of the analysis of this paper, central deficiencies of the present regulatory framework in view of distributional effects between prosuming and purely consuming households are identified – and quantified.

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[13] Solargesetz Berlin as of July 5, 2021 (Gesetz- und Verordnungsblatt für Berlin, 77. Jahrgang, Nr. 54, 15.07.2021); Hamburgisches Gesetz zum Schutz des Klimas (Hamburgisches Klimaschutzgesetz - HmbKliSchG) as of February 20, 2020 (HmbGVBl. 2020, 148); Verordnung des Umweltministeriums zu den Pflichten zur Installation von Photovoltaikanlagen auf Dach- und Parkplatzflächen (Photovoltaik-Pflicht-Verordnung - PVPf-VO) (Baden-Württemberg) as of October 11, 2021 (GBl. 2021, 847).

Socioeconomic impacts of the EEG over the past 20 years

In the electricity sector alone, the net annual benefit for prosumers compared with consumption-only households is EUR 458 on average for all of Germany (2021). That is, in 2021, an average consumer household paid EUR 458 (75%) more for electricity supply than an average prosumer household, in consideration of both the benefits prosumers receive via FITs and their annualized PV and battery investment costs (H1). This cost delta is driven by the interplay of two different effects. First, especially from 2005 to 2012, an over-subsidization of PV investment costs occurred, i.e., feed-in tariffs were disproportionaley high compared with the actual investment costs (margin effect). Second, for small-scale systems installed after 2012, pure feed-in of produced electricity has no longer been economically attractive. Instead, since 2012, there has been an economic incentive to maximize self-consumption (self-consumption effect), because (average) retail electricity prices have been higher than FITs; see Figure 1-1. The magnitude of this self-consumption effect has significantly increased since 2012, because it scales directly with the spread between retail electricity price and FIT – which has risen to nearly 25 ct/kWh on average in Germany (2021).[14] Current global developments, such as Russia's war on Ukraine and the associated consequences for the European energy supply, are leading to permanently high electricity price levels in the medium term and thus to an increase in the incentive for self-supply. These findings add to the vast existing literature on the general distributional effects of RES support schemes and corresponding socioeconomic effects, e.g., studies by Bird et al., 2013, Bertsch et al., 2017, and Sabadini and Madlener, 2021, and literature on the distributional effects of the EEG in particular, e.g., studies of Grösche and Schröder, 2014, and Frondel et al., 2015. In contrast to the present thesis, however, these existing works are based either on mere theoretical considerations or on prototype residential households rather than a complete set of empirical data including approximately 1.4 million households with small-scale PV as is used in Paper A, Section 3.

Present magnitude and future development of the distributional consequences of the EEG

The current extent of the distributive effects of the EEG becomes apparent when considering cumulative sums over all households in Germany. As a consequence of the margin effect and the self-consumption effect, in 2021, EUR 553 million shifted from consuming households to prosuming households, and the self-consumption effect accounted for EUR 250 million – almost half – of this effect (45%). Moreover, should the present regulatory

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[14] Average retail electricity price (2021): 32.48 ct/kWh; average FIT (2021): 7.53 ct/kWh; source: BDEW Bundesverband der Energie- und Wasserwirtschaft, 2022.

framework not be adjusted, the distributional consequences of self-consumption would further increase in the future for four reasons occurring in parallel. First, current legislative stipulation such as the solar duty for new buildings and a market environment with persistently high electricity (energy) prices drives the accelerated installation of new small-scale PV capacities. Second, all newly installed small-scale PV systems are currently operated for self-consumption maximization. Third, older small-scale PV units that phase out of EEG support after 20 years continue to be operated to maximize self-consumption. Fourth, achievable self-consumption amounts are further increased by electricity based applications from the heat and mobility sectors, such as electric heat pumps and electric cars.

Manifestation of distributive effects at higher levels of aggregation

The socioeconomic inequalities between individual households that result from the EEG persist also at higher levels of aggregation. At the NUTS3 level in particular, significant differences arise in the average household electricity costs. Few municipalities, especially in the southeast, have comparatively low average household electricity costs, while the majority of municipalities bears higher average household electricity costs. This socioeconomic dichotomy has essentially persisted over the past 20 years, demonstrating that the spatially unequal allocation of regulatory benefits and costs is structural in nature (H2). The uneven socioeconomic distribution is directly attributable to the regional differences in installed small-scale PV capacities. In other words, the EEG has failed to ensure that the existing technical (rooftop) potential for small-scale PV is exploited evenly across Germany. In 2021, approximately one quarter (26%) of the 401 German municipalities had a technical potential exploitation below 3%, whereas only one eighth (13%) of the municipalities had exploited more than 10% of their technical potential, resulting in an average potential exploitation of 5% for the whole of Germany. These results add to the existing literature, e.g., studies of Többen, 2017, Grover and Daniels, 2017, and Allan and McIntyre, 2017 for country case studies of the United Kingdom. These works are, however, either limited to an incomplete consideration of the actual net benefit (e.g., they do not consider investment costs; see Grover and Daniels, 2017) or have a lower spatial resolution; see Többen, 2017.

Generality of effects

In Paper B, Section 4, the analysis of empirical data from Paper A is based on a more general theoretical foundation. Using a linear optimization model of an electricity market that is loosely informed by the German market size with regard to electricity (and residential heat) demands and number of households, it can be demonstrated that prosumer households will optimize themselves at the expense of other households by increasing their self-consumption ratios. This statement is of general applicability because it is derived from a relatively small set of basic regulatory assumptions that have been abstracted from the existing EEG. In this context, key variables such as the level of FITs and volumetric price components such as network charges are directly derived from corresponding system quantities. By construction, this analysis excludes potential margin effects associated with FITs. Nevertheless, it can be shown that even for such "ideal" FITs under perfect market foresight, distributional effects occur due to the indirect incentive to maximize self-consumption. In particular, the analysis shows that the current form of volumetric network charges, which could be circumvented by self-consumption, contributes substantially to the redistributive nature of self-consumption maximization, accounting for approximately 60% of the effect.

Natural limits of decentralization

Prosumers not only try to maximize their self-consumption by the corresponding operation of their flexibilities, but also direct their investment decisions accordingly. From the individual household perspective, for prosumer households with PV, battery storage, electric heat pumps, and thermal storage, self-consumption ratios of approximately 60% seem to be economically optimal, assuming average sizes for the capacities of installed applications; see Section 4. Higher self-consumption ratios could only be realized by investing in ever larger storage capacities, which is not economically viable. It should be noted that the numerical value of 60% serves as a broad orientation, depending on the parameters chosen, and may alter for different parametric assumptions in general and for individual household settings in particular. Regardless of the specific numerical value, the relevant finding is that the decentralization of the energy system has natural limits based on economic principles, illustrated by the U-shape of Figure 1-2. In other words, future energy systems will continue to have a hybrid character, consisting of centralized generation, storage, transport, and distribution infrastructures on the one hand and decentralized generation and storage systems, including millions of small-scale units, on the other hand. This illustrates the need for distributed RES systems to communicate and interface with the surrounding systems in a coordinated manner – this issue is addressed in Section 6.2.

6.2 System effects from large-scale prosumer penetration

Having analyzed the impacts of prosumers at the household level, we now focus on the effects on the system as a whole. Paper B, Section 4, demonstrates that prosumers represent an important source of investment in RES and may provide private financing capital. For reasonably low electric – and in case of large-scale heat pump penetration also thermal – storage investment costs, self-consumption maximization is mainly achieved via investments in corresponding storage capacities.

System effects of prosumer investment decisions

By investing in storage capacities, prosumers can produce and integrate RES into the energy system. Thus, striving for high self-consumption ratios could contribute not only to the system integration of RES but also to the reduction of CO_2 emissions. High levels of self-consumption could allow the system to reduce its operating costs – mainly by saving fuel and corresponding CO_2 costs and, to a smaller extent, also by saving start-up costs of thermal power plants – but at the same time lead to storage redundancies. From a system perspective, the operating cost advantage is overcompensated for by the resulting higher investment costs, leading to an overall increase in total system costs. For a future energy system, oriented to the size of Germany, the presence of 20 million prosumers could therefore lead to an annual system cost increase of EUR 380 million (0.42% of the assumed total system cost basis). However, as noted, this increase in system costs is borne by prosumer households themselves. Moreover, the analysis shows that such additional costs inevitably arise only at very high self-consumption rates – 60% under the parametric assumptions of Paper B. Conversely, the overall electricity market can, in principle, tolerate moderately high self-consumption levels without incurring additional system costs. Under the parametric assumptions of Paper B, a self-consumption ratio of 47% is the tipping point at which additional system costs arise (S1). These results add to Schill et al., 2017, finding of similar increases in total system costs as a consequence of non system-oriented prosumer behavior. Again, the precise numerical values (which depend on the chosen parameterization) are less important than the relative relationship between system-optimal and household-optimal self-consumption ratios. Above a certain threshold (here, 47%), the maximization of self-consumption stimulated by the regulatory framework (here, up to 60%) inevitably leads to additional costs in the overall system.

Consideration of strategic behavior in operation

So far, it has been assumed that prosumers strategically optimize their own investment behavior, but make their flexibilities available to the system during operation to serve the system as a whole. Such a system-beneficial prosumer behavior is often – directly or indirectly – assumed in the existing literature – although this assumption could significantly overestimate the actual flexibilities provided by prosumers. In other words, what is important is not only *how much* self-consumption prosumers strive for but also *how* they achieve it with respect to the algorithms and heuristics they apply to operate their flexibilities. Therefore, a major additional value of the analysis of Paper B is the study of strategic prosumer behavior in operation and the quantification of its impact on the overall system. Paper B demonstrates that different flexibility operating modes result in significantly different system cost increases. If the prosumer flexibilities are operated in a completely inflexible manner from a system perspective, the system cost increase can almost quadruple, resulting in a total system cost increase of EUR 1,150 million (1.30% of the total system cost base), EUR 770 million of which is directly attributable to effects from non-optimal operation (S2). This system cost increase mainly results from a reduced overall RES integration because prosumers primarily optimize the integration of (small-scale) PV. Other RES, such as on- and off-shore wind, with other variable production profiles, however, may be integrated into the system much less effectively. Thermal power plants with correspondingly high fuel and CO_2 costs must consequently be deployed more frequently, leading to corresponding additional system costs. Moreover, individual optimization of prosumers could induce additional stress on dispatchable power plants that need to balance total demand and generation, resulting in higher start-up costs and higher pump storage activity. This may even lead to a situation that is counterintuitive at first glance, where additional (distributed) storage capacity is installed at the same time as total CO_2 emissions *increase*.[15] A comparable analysis including a detailed break-down of the total system cost effects caused by the strategic behaviour of prosumer households has not been carried out before.

Robustness of results

A parameter variation analysis conducted in Paper B, Section 4, demonstrates that the magnitude of resulting system effects depends on four classes of model assumptions: overall system flexibility (including central storage systems and interconnections to other coun-

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[15] Note that unlike the European Union Emissions Trading Scheme (EU ETS), this analysis uses a CO_2 price rather than a CO_2 emissions cap. In the EU ETS, a maximum cap is set on the total amount of CO_2 and CO_2 equivalents that can be emitted. Thus, the effect of increasing CO_2 emissions in the analysis is to be interpreted as a (local) increase within a subsystem of the EU ETS, i.e., as a shift within the EUT ETS.

tries); variable RES production and demand profiles; the number of prosuming households; and overall parametric uncertainties, including specific cost assumptions and technology characteristics (power plant efficiencies, full load hours, etc.). The analysis demonstrates that the system effects become relevant at 10 million prosuming households (25% of all households), causing an increase in total system costs of EUR 140 million, corresponding to 0.16% of the respective total system cost base. Particularly regarding the influence of profiles, the robustness of these results is further reinforced by the analyses of Paper C, Section 5. In contrast to Paper B, which is based on representative synthetic load profiles[16] in Paper C the effects of prosumer behavior are derived on the basis of measured quarterhour data of real households. Moreover, system cost differences in Paper C include only the effects of flexibility operation, the effects of investment decisions are excluded. As a result, a total system cost difference of approximately EUR 400 million between market-beneficial and purely household-beneficial prosumer behavior is found. This value is of the same order of magnitude as – but lower than – the corresponding value from Paper B (EUR 770 million), which is consistent with the fact that Paper C is limited to PV and batteries as prosumer technologies, whereas Paper B additionally includes electric heat pumps and thermal storage.

Integrating prosumers into the market

In Germany in particular, the interplay of high electricity prices; comparatively low feed-in tariffs; and the granting of exemptions from levies, surcharges, and taxes on self-consumption leads to a special regulatory treatment of self-consumption, which results in prosumers increasingly disconnecting themselves from the system. Hence, to fully exploit the system benefits of prosumers and prevent additional costs, the decisive factor is how strongly prosumers are actually integrated into the market. In this context, Parag and Sovacool, 2016, for instance, qualitatively consider possible schemes to integrate prosumers into the market or to create new local markets on the basis of a peer-to-peer approach. From a system perspective, full integration of prosumers into the wholesale market would be cost-optimal – neglecting possible integration costs (which are outside the scope of the present thesis). Moreover, such full prosumer integration would, in principle, be compatible with the desire for moderate to high self-consumption, but it would have to be accompanied by a major paradigm shift. This is because it requires prosumers, in principle, to relinquish some of their control over their distributed systems so that their systems can operate flexibly in interaction with the surrounding energy system. A realistic compromise between the present, quasi-absent market integration and the desired full market integration of prosumers could be the application of intelligent algorithms. On the one

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[16] So-called H0-profiles; see BDEW Bundesverband der Energie- und Wasserwirtschaft, 2000.

hand, these algorithms could guarantee a maximization of annual self-consumption, and, on the other hand, they could preserve a large part of the – short-term – flexibility that the distributed prosumer households could provide. Given the parametric assumptions of Paper B, Section 4, the application of these smart algorithms could create a total financial benefit for the system of EUR 770 million per year, which precisely corresponds to the cost difference of completely inflexible (EUR 1,150 million) and flexible (EUR 380 million) operation of the distributed prosumer systems. Evaluating the necessary investment required to implement these algorithms on a large scale is beyond the scope of this thesis. However, it should be noted that a large proportion of these cost effects could presumably be realized by scalable software solutions – without the need for installation of additional hardware.

6.3 Local network effects

As a third level of scale, Paper C, Section 5, focuses in particular on the effects at the distribution network level. Here, the main objective is to understand the relevant effects on the distribution network in the context of effects at the aggregation level below (household level) and the aggregation level above (wholesale market level). To this end, the situations of maximum residual load on a local network node are evaluated for different prosumer behavior, i.e., different battery operation modes. Although the approach is simplified in some respects – the assumption of a radial network topology, the assumption of high R (resistance) / X (reactance) ratios, and the use of measured data of a prototype household – some insights into the basic structure of future network stress situations can be derived.

Stress situations on the local distribution network

Situations of extremal peak-coincident network capacity utilization are an indicator for the thermal stress level of the local network node. Here, the resulting capacity utilization depends on both the height of profile peaks of the individual households and the simultaneity of occurrence of these indiviual profile peaks. Therefore, a crucial part of the work of Paper C, Section 5, consists of a detailed study of corresponding simultaneity factors for PV production and household load profiles. The results show that for moderate (25%) and medium (50%) prosumer shares, referring to the percentages of households that act as prosumer households in a future energy system for the size of Germany, the thermal network stress is typically induced by load peaks. This situation changes for higher prosumer shares (75%), when the network stress is predominantly caused by feed-in peaks of surplus prosumer electricity from PV. Different prosumer behavior leads to significant differences in peak-coincident network capacity utilization. In contrast to the two preceding works (Papers A and B, Sections 3 and 4, respectively), Paper C, Section 5, not only assesses the differences between household-oriented and market-oriented behavior, but also focuses on network-oriented behavior as a third option for strategic prosumer behaviour. By construction, grid-oriented battery operation results in the lowest possible network utilization peaks. By contrast, household-oriented behavior, which is implemented as a static prosumer heuristic to maximize self-consumption, results in up to 32% higher network utilization than that in a grid-oriented strategy (N1). Market-oriented battery operation to minimize total system (wholesale market) costs relieves the network better than self-consumption maximization, but it still results in an – albeit moderately – higher (5%) network capacity utilization.

Trade-offs between network and market perspectives

Network-beneficial storage operation could result in an increase in total system costs. Given the parametrization of Paper C, Section 5, the system cost delta between market- and network-oriented battery operation is EUR 400 million, corresponding to 0.8% of the total system cost base. The paper contributes to revealing and quantifying the possible trade-offs between individual, network, and market optimization – under realistic consideration of the incentives provided by the underlying regulatory framework (N2). The analysis of Paper C is further supported by findings from Paper B, Section 4, which also evaluates the maximum of (hourly) feed-in peaks of prosumer households. The main finding is that maximization of self-consumption by means of investment in distributive storage can actually relieve the distribution network by approximately 18%[17] – if the distributed flexibilities are operated system-beneficially. However, if prosumers apply a predetermined, static heuristic to achieve maximum self-consumption ratios, the stress level on the local network could increase by 7% (4.27 kW per household) – independently of the installed storage capacities. These findings are in line with existing literature, e.g., Moshövel et al., 2015, and Neetzow et al., 2019. However, in contrast to the present work, in these studies, the discussed network effects are not considered in the overall context of corresponding wholesale market impacts. As an interim conclusion, future large, distributed storage capacities taken by themselves cannot indicate the extent to which the local distribution network is relieved or put under additional stress. However, if future large numbers of prosumers seek to maximize their self-consumption ratios in an inconsiderate manner, the stress level of the local network could increase noticeably, and additional network operation and infrastructure costs could be incurred.

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[17] Reduction in maximum feed-in peaks from 4 kW to 3.27 kW per household.

6.4 Overall conclusions and policy implications

Having identified major deficiencies of the present regulatory framework, this work aims to outline possible modifications for a better, i.e., system-serving and cost-avoiding, large-scale integration of prosumer households. The approach is twofold.

First, we analyze a potential change to the network charge design in view of effectiveness and possible trade-offs to be considered. A modification of the network charge design provides a reasonable starting point for adjustments of the regulatory framework. This is because network charges represent the largest single regulatory price component of the residential electricity price, accounting for more than 20% of the retail electricity price in the first half of 2022 (8.08 ct/kWh of 37.14 ct/kWh); see BDEW Bundesverband der Energie- und Wasserwirtschaft, 2022. Network charges consequently have a significant redistributive effect between households. Moreover, future large-scale prosumer penetration will lead to significant impacts on local distribution networks – and prosumers will be able to affect the actual stress levels on local network nodes through their behavior. It therefore seems reasonable to start at this point of the regulatory design and replace the present, mostly static design with new mechanisms.

Second, and finally, we take the discussion to a higher level of abstraction to discuss fundamental guiding principles that should direct the design of the future regulatory framework.

Consideration of a new network charge design

To begin, Paper C, Section 5, analyzes a new network charge design that is based on peak-coincident network capacity utilization rather than volumetric allocation of network costs to the energy withdrawn from the network; see Perez-Arriaga and Knittel, 2016, for a detailed depiction. Two main ideas underlie this approach. First, the present (volumetric) network charge design violates the cost-by-cause principle in that grid infrastructure and operation costs are not based on marginal costs or operational usage. This means that the individual benefit of a (prosumer) household avoiding network charges does not result one-to-one in overall lower network costs. On the contrary, the analyses of the present work show that higher self-consumption ratios, i.e., less amounts of electricity withdrawn from the public grid by prosumers, could even lead to an increase in stress levels on the local network – depending on the mode of operation of the distributed flexibilities. Therefore, peak-coincident network charges could accurately depict the correlation between actual use of the network infrastructure and associated costs because, in theory, the local network would be ideally sized for the amount of maximum residual load. The current distortion could be illustrated with an extreme example: In the present volumetric scheme, a prosumer household that would draw electricity from the public grid for only one hour a year – and would have the security of doing so at any time – pays only negligible network fees. However, this could change in a design based on capacitive grid charges. Both Paper B, Section 4, and Paper C, Section 5, provide estimates for the magnitude of the redistributive potential of (changes to) the network charge design. Based on the parametric assumptions in Paper B, the share of network charges in the redistributive effect between prosumers and consumers is more than half (57%) of the total effect. Paper C further substantiates this finding and quantifies the extent to which peak-coincident network charges could reduce existing differences between household electricity costs. Prosumer households could face annual network fees more than EUR 300 (EUR 303 per year) higher than with volumetric charges, while consumer households could be relieved by this amount (EUR 294 per year), resulting in a financial convergence of nearly EUR 600 per year.

Second, in addition to mere redistributive effects, a network charge design based on capacity rather than volume could set appropriate incentives for prosumer households to operate their flexibilities to relieve the distribution network. The analysis in Paper C, Section 5, indicates that the effects could be significant for local network nodes to which a large number of prosumer households are connected to, that is, incentivizing grid-oriented storage operation could relieve the local network by up to one third compared with a static prosumer heuristic. As previously discussed in Section 6.2, such intelligent flexibility operation, which relies on local systems communicating with their surrounding environment, implies a paradigm shift with respect to current notions of autonomy and control of distributed energies. Nevertheless, already today both investment and operation decisions are strongly based on financial motives, see Allan and McIntyre, 2017, for instance, suggesting that a modified regulatory framework with appropriate incentives may contribute to the needed behavioral changes.

Third, and finally, the coherent depiction of individual (household), local (network), and global (market) effects illustrates the trade-offs of potential interventions in the existing system that must be carefully weighed. Specifically, the introduction of capacitive network charges and, accordingly, incentivized network-serving behavior could result in additional costs at the wholesale market level. More importantly, the associated redistributive effects[18] could, at worst, make private investment in small-scale RES less economically attractive – which must be avoided in order not to jeopardize the necessary PV installation rates. Resolving or mitigating these partly conflicting goals is one of the most challenging issues in modifying the regulatory framework and is beyond the scope of the present work. In fact, the aspects discussed in the three journal contributions of which

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[18] That is, a reduction in the burden on consumers and an additional burden on prosumers.

the present thesis is composed, represent only a few of many considerations in the field of research on future energy market designs.

Guiding principles of the future regulatory framework

Thus, in addition to the specific discussion of capacity-based network charges, more general, fundamental guiding principles for the future design of the regulatory framework can be derived from the findings of this work.

The first guiding principle is **transparency**: All three papers highlight that there is a lack of quantitative evaluation of the socioeconomic impacts of the present regulatory framework, with regard to both redistributive effects and economic effectiveness. For a quantitative assessment of the policy instruments in place, currently isolated data must be systematically linked. This encompasses technical data of installed PV and storage capacities from the *Marktstammdatenregister* (market master data registry; see Bundesnetzagentur, 2022); socioeconomic data, including PV and storage investments costs, feed-in tariffs, network charges, and retail prices; and operational data such as self-consumption ratios. On this basis, predefined quantitative socioeconomic measures could be evaluated on an ongoing basis, which would allow for an assessment of the existing regulatory instruments and possible adjustments as needed. With regard to the energy transition in Germany, the existing lack of transparency is confirmed by the German Federal Court of Audit (Bundesrechnungshof), noting, for instance, a lack of measurability in the monitoring of the German energy transition; see Bundesrechnungshof, 2021.

The second guiding principle is **directness**: The analyses of the present work show that a large part of the redistributive effects of the existing regulatory framework is of an indirect nature because, in fact, the direct incentive of FITs is the full feed-in of produced energy, not self-consumption. However, the interplay of falling FITs and rising retail electricity prices has created a prosumer business model that is based on an ever-increasing decoupling from the overall system. Regulatory instruments must consequently consider the full context. The present work has worked through the interplay between wholesale prices, FITs, network charges, retail prices, and self-consumption. Understanding the interferences of the regulatory instruments aids in modifying the regulatory framework to increase its directness and to eliminate unintended effects. These unintended effects of the indirect nature of incentives have been widely illustrated in the existing literature, e.g., in the analysis of Eid et al., 2014 on the effects of cross subsidies from tariff designs to promote residential PV. Furthermore, in terms of spatial impact, the interplay between global (federal) legislation and actual local impacts should be monitored more closely in the future. This is because, according to the analysis of the present thesis for the country case of Germany, distributed RES installations are currently concentrated in a few areas, leaving large portions of the landscape unused to date.

The third guiding principle is **cost causation**. This principle is closely connected to the principle of directness. The cost causation principle is violated in crucial areas of the current regulatory framework. One important example is the refinancing of network infrastructure costs via volumetric network charges. After all, the dimensioning of the network infrastructure and thus the corresponding cost basis is determined only in part by the volume of energy transmitted, but to a considerable extent by the peak capacity utilization. The lack of incentives to avoid power peaks in the present regulatory framework, e.g., the non-priced feed-in of excess energy from prosuming households, leads to misdirected incentives, e.g., pure self-consumption maximization instead of grid-relieving modes of battery operation. In addition, grid costs are unfairly distributed at the expense of traditional consumers, which – in the worst case – could in turn jeopardize the general acceptance of the energy transition. The cost causation principle is reflected many times in the existing literature, e.g., with Kirby et al., 2006, stating that ”tariffs for regulation and imbalance services shoud (...) properly allocate those costs to those entities that cause the balancing authority to incur the costs”, and Perez-Arriaga and Knittel, 2016, stating that prices and regulated charges for power systems ”should send efficient economic signals to agents in the system”.

The fourth and final guiding principle is **flexibility**. So far, the regulatory framework creates static incentives for self-consumption maximization. Prosumers hence operate their distributed systems by predetermined heuristics that largely lack flexible interaction with the surrounding system. At the same time, the influence of prosumer behavior is no longer confined to the original electricity market; but it now encompasses heating (electric heat pumps) and transportation (electric cars) as well. This makes it increasingly important to integrate prosumers smartly into the energy system. In this context, it is particularly important to understand sector integration as not only a technical challenge but also a regulatory challenge; see Wietschel et al., 2018, for instance. One of the main problems at present is that different energy sectors – namely private households, trade/commerce/services, industry, and transporation[19] – and different energy sources – namely fossil fuels (including hard coal, lignite, petroleum and natural gas), renewable energy sources, electricity, and district heat[20] – are treated differently in terms of levies, surcharges, and taxation due to a large number of individual provisions based on the concept of a largely centralized energy system. Therefore, it is important to recognize that successful integration of millions of prosumers into a decentralized energy system requires a change to the existing regulatory framework in terms of enabling and incentivizing system-serving flexibility, as outlined, for instance, by Parag and Sovacool, 2016.

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[19] Energy sector definition according to AGEB AG Energiebilanzen, 2022.

[20] Energy source definition according to AGEB AG Energiebilanzen, 2022.

With regard to Germany, BDEW Bundesverband der Energie- und Wasserwirtschaft, 2017 recognizes the potential of flexibility provided by different stakeholdes within a sector-integrated energy market and regards corresponding adjustments of the regulatory framework to be indispensable.

6.5 Limitations and recommendations for future research

This section discusses the limitations of the present work and possible areas for future research. First, the present work is limited in terms of the level of detail in the **disaggregation of household groups**. All three papers generally distinguish only two household groups: prosumer households (prosumers) and non-prosumer households (consumers). This rather stylized approach is sufficient to analyze effects of structural nature (see Sections 4 and 5, in particular) and determine robust estimates for effects at average household level (see Section 3). However, future research should take these analyses further with a more detailed breakdown of household demands and load profiles to increase to robustness of the quantitative results. Greater differentiation between different household groups could well affect quantitative results at all three scales of the energy system – household, network, and wholesale market. At the household level, a more detailed representation of prosumer households would likely lead to a greater variance in the actual achievable self-consumption ratios. As demonstrated in this work, these self-consumption ratios are, in turn, the scaling factor for the economic advantage of prosumer households over consumer households. Moreover, the actual extent of socioeconomic inequality is determined by other variables that are represented by average values in this thesis but could be mapped at higher resolution in future research. This refers to the spatial resolution of installed battery storage capacities, regional differences in investment costs, and spatial variations in retail prices caused by regionally different network charges. Similarly, a more detailed household disaggregation would affect the results at the local network and system levels. For the network level analysis, the peak-coincident network capacity utilization strongly depends on the actual load profiles of the households connected in the local node's vicinity. Therefore, a more detailed break-down of both prosumer and consumer household profiles could make the results presented in Section 5 more robust by quantifying the possible ranges of peak-coincident network utilization. Even though cross-shifts in the self-consumption of individual households should partially resolve statistically at the aggregated system level, a more detailed depiction of household groups could also affect the results at the wholesale market level. This applies to all effects caused by structural differences that cannot be resolved by aggregation, such as the structural differences in the building stock and the associated technical potentials for PV and achievable self-consumption ratios. In particular, based on the work of the present thesis, it is reasonable to expect that the existing regulatory market framework actually leads to far greater economic inequalities among certain household groups than suggested by the aggregate values examined in the present thesis.

Second, regarding the analysis of local network effects, future research could conduct **explicit load flow calculations** on the basis of the results of this work. Doing so would allow for a deeper understanding of the actual stress levels that might be induced through the respective prosumer battery operation. The network analysis of the present work is limited by a few simplifications such as the assumption of a radial network topology and consideration of thermal stress on components only, neglecting other aspects, for instance, phase voltage unbalance. In particular, it can be assumed that the spatial variance of the peak (residual) load situations due to prosumers can be considerably high. This would mean that local distribution networks in certain areas could reach their capacity limits much earlier than suggested by the highly stylized analyses of the present thesis – this should be substantiated by further research.

Third, this work has a clear focus on the electricity sector, analyzing the combination of distributed PV and residential battery storage systems in detail. In addition, relevant prosumer applications of other sectors such as electric heat pumps (Section 4) and electric cars (Section 5) are partially considered in this work. However, future research could provide more detail, particularly on the **impact of widespread e-mobility**. In Paper 5 electric cars are primarily considered as an additional load source, whereas widespread e-mobility could also represent an important source of flexibility in the future energy system, for instance by means of dynamic charging schemes or vehicle-to-grid applications. This possibility becomes particularly evident when the technical flexibility potential of e-mobility is illustrated in comparison to the typical dimensions of stationary household battery storages. Today (2022), a typical battery of an electric car is well within the range of 60 kWh, whereas current stationary battery storage contents are smaller by about a power of ten. Moreover, future research should consider the necessary technical *and* regulatory prerequesites regarding communication interfaces and standards between home energy management systems (inverters) and electric vehicles (charging sations). The multiple uses of electric vehicles as transport, energy storage and system service providers are expected to further increase the influence of prosumers in the future. This could exacerbate the effects analyzed in the present thesis at all scales of the energy system and should be further explored by future research.

Fourth, the present work focusses on the quantification of the monetary benefit for the energy system when millions of prosumer households operate their distributed flexibilities in a system-oriented way. To quantify the actual net benefit to the system, future research should determine the **specific technical requirements and associated costs for implementation**. Section 6.2 argues that scalable software solutions could realize large parts of the system benefit – this argument should be substantiated by further research.

Fifth, the results of this thesis heavily depend on the actual control algorithms of the distributed systems. Sections 4 and 5 analyze different control algorithms that serve as extreme strategies for operating the distributed flexibilities, that is, chronological charging (household-oriented), peak shaving (network-oriented), or fully wholesale market price reactive (market-oriented). Throughout this thesis, perfect foresight is assumed for all control algorithms. Future research could analyze the implications of a **more realistic representation of future control algorithms**, including the effects of limited forecasts of the variable PV production, household load, and wholesale market prices. To do so, these control algorithms should ideally seek an optimal trade-off between the interests of individual prosumers, such as ensuring a minimum level of required annual self-consumption that must not be undercut, and system benefits, such as reducing grid load at peak times and reaction to the real-time wholesale market price signal. Doing so would allow a deeper understanding of the interdependencies between households, the local network, and the overall system.

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Content

The decarbonization of the global energy system requires the deployment of distributed renewable energy sources (RES). This process involves an increasing number of active market participants, called prosumers, who *pro*-duce and con-*sume* energy by means of distributed generation and storage systems. In Germany, approximately 1.4 million small-scale photovoltaics (PV) units below 10 kW have been installed to date (2021), supported by the Renewable Energy Sources Act (EEG). Although prosumers represent an important source of private RES investment, the current regulatory framework does not yet provide sufficient incentives for these distributed systems to be integrated in a fully system-serving way. On the contrary, for small-scale PV, the regulatory incentive over the past decade has been solely to maximize self-consumption. The actual behavior of prosumers in response to the regulatory framework consequently affects the energy system at different scales: Prosumer behavior can induce (a) distributional effects at the household level, (b) (thermal) stress at the local network level, and (c) additional system costs at the wholesale market level.

A deeper and quantitative understanding of these interferences between prosumers and the power system at different scales is the objective of this cumulative thesis encompassing three peer-reviewed journal papers. Based on empirical data and using statistical measures, the first paper examines the household-level impacts of the EEG over the past 20 years. The results show significant regional differences in both the utilization of the technical rooftop potential and the allocation of net benefits from the EEG. As a result, aggregated over the whole of Germany, the EEG leads to a cost shift of more than half a billion euros to the detriment of traditional consumer households. The second study focusses on system-level impacts from distributed PV, battery storage, heat pumps, and thermal storage. To realistically depict the effects of strategic prosumer behavior, corresponding constraints are implemented in a linear optimization model of the German electricity market. As a result, with future high RES and prosumer shares, inconsiderate operation of distributed flexibility options, as incentivized by the present regulatory framework, could incur additional system costs of more than EUR 1 billion. The third paper concludes the analysis by studying possible local network effects associated with the widespread emergence of prosumers. By coupling different control algorithms of distributed PV and battery systems with a simultaneity analysis of the local network capacity utilization, it can be shown that network-oriented operation of distributed flexibilities could significantly relieve the local distribution network. The necessary change in prosumer behavior could be achieved via a new, capacity-based network charge design. The assessment of the associated effects at the system and household levels form the concluding considerations of the study, demonstrating possible target conflicts between network- and system-oriented flexibility operation.

Based on the findings of this thesis, we reason that the future design of the regulatory framework should incorporate transparency, directness, cost causation, and flexibility as fundamental guiding principles.

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