Energy communities' flexibility in different tax and tariff structures

Johannsen, Rasmus Magni; Sorknæs, Peter; Sperling, Karl; Østergaard, Poul Alberg

Published in:
Energy Conversion and Management

DOI (link to publication from Publisher):
10.1016/j.enconman.2023.117112

Publication date:
2023

Document Version
Publisher's PDF, also known as Version of record

Energy Conversion and Management 288 (2023) 117112

Contents lists available at ScienceDirect

Energy Conversion and Management

journal homepage: www.elsevier.com/locate/enconman

Energy communities' flexibility in different tax and tariff structures

Rasmus Magni Johannsen *, Peter Sorknæs, Karl Sperling, Poul Alberg Østergaard

Department of Planning, Aalborg University, Rendsburggade, 14, 9000 Aalborg, Denmark

ARTICLE INFO

Keywords:
Energy community
Energy planning
energyPRO
Flexibility
Electricity grid tariffs

ABSTRACT

Energy communities are often referred to as a potential source of flexibility to energy systems. However, the extent remains uncertain and is dependent on both the technologies and market structures present. This study models an energy community under different technical system configurations subject to different electricity tax and electricity grid tariff schemes to determine flexibility potentials and effects on the surrounding energy system. It is found that unless incentivised to reduce electricity grid imports, or that import capacity is otherwise restricted, the electrification of energy communities will significantly increase the electricity import from the surrounding electricity grid and thus increase the required electricity grid capacity. This can largely be negated by restructuring tax and tariff schemes to incentivise flexibility and a more temporally distributed consumption pattern. Most notably, capacity payments prove an effective measure in this regard. The operation of the energy community was generally found to be well-aligned with the operation of a future national 100% renewable energy system, indicating that there are no inherent critical contradictions in the expected operation of this kind of energy community and a surrounding national energy system.

1. Introduction

Energy systems are undergoing a process of decentralization and a transition from large-scale centralized energy production to decentralized small-scale energy production and variable renewable electricity (VRE) production [1,2]. Likewise, energy planning is no longer solely a task undertaken by central (national) authorities but is also going through a process of decentralisation [3] as municipalities [4,5], cities [6] and even local communities [7] are involving themselves in energy planning. Representing the local level, local energy communities have emerged as an entity for organising local energy consumers and producers, and ideally promoting, both, decentralisation and democratisation of energy systems [8].

The European Commission introduced two related concepts under the same umbrella definition of energy communities: "Citizen Energy Communities" [9] and "Renewable Energy communities" [10]. These concepts have been implemented in the national legislation of European Union (EU) member states, providing communities organised by consumers the opportunity for regulated access to energy markets [11]. It is the intention that both community concepts are based on open and voluntary participation from citizens, municipalities or smaller businesses, and the main purpose is to generate societal benefits rather than solely financial profits.

In a more practical sense, an energy community is a group of people or organizations that work together to develop and implement strategies for the production and use of energy in a particular area, typically for a city, neighbourhood, or district [12]. The goals of an energy community are generally to increase the use of renewable energy (RE) and reduce reliance on fossil fuels, improve energy security, reduce environmental impacts, and promote local economic development [13].

Energy communities can in principle help to reduce energy system costs and increase energy independence, while also promoting the use of RE and reducing greenhouse gas emissions [14,15]. They can also foster a sense of community, encourage collaboration and innovation, and serve as a way of engaging and organising local communities in the energy transition through a closer connection to the local society [16,17], rather than an abstract national energy system. However, energy communities also introduce a very local scale of planning that is not necessarily practical from a holistic planning perspective, and the emphasis on delimited local systems is potentially sub-optimal from a

Abbreviations: BBR, Building and Housing Register (In Danish); DH, District heating; DSO, Distribution system operator; EV, Electric vehicles; EC, Energy community; EU, European Union; HP, Heat pump; IDA, Danish Society of Engineers; IDA2045, IDA Climate Response 2045; PV, Photovoltaics; RE, Renewable energy; TOU, Time-of-use; TSO, Transmission system operator; VRE, Variable renewable electricity; WT, Wind turbine.

* Corresponding author.
E-mail address: rmj@plan.aau.dk (R.M. Johannsen).

https://doi.org/10.1016/j.enconman.2023.117112
Received 14 February 2023; Received in revised form 24 March 2023; Accepted 24 April 2023
Available online 12 May 2023

system perspective [18]. It is thus imperative that the anticipated system effects of energy communities are thoroughly investigated before widespread adoption.

Planning for a local system such as an energy community is a much more confined task as opposed to the energy planning conducted for, e. g., national systems or even decentralised authorities such as regions or municipalities. Energy communities thus provide opportunities for functioning as a testing ground for technologies and measures difficult to implement at a larger scale. Also, technologies that are economically or practically infeasible to implement from an individual household perspective could be implemented by an energy community as a group, e.g., energy storage facilities, common electrical vehicle (EV) charging capacity, or even a local district heating (DH) system. Implementing such local technologies and measures would potentially enable energy communities to provide several system benefits, including flexibility, assuming regulatory and market structures enable and incentivise flexible behaviour.

1.1. Energy communities as a source of flexibility

Future RE systems need flexibility mechanisms to accommodate the fluctuating nature of RE production [19]. Arguably, such flexibility could be provided at all scales, whether that is at an international, national, or local level. The local level in particular as a flexibility provider is explored by Backe et al., modelling the impact of energy communities on the European electricity and heat system, finding that a wide deployment of energy communities can contribute flexibility to a more cost-efficient decarbonisation [20]. They find that the development of energy communities lowers the need for storage capacity on a European level and shifts generation capacity from building-level heating capacity to electricity generation capacity due to the resulting increased electrification. On a distribution network level, the flexibility provided by energy communities could strengthen areas with weak grid connections, effectively reducing immediate needs for grid expansion [21–23]. This, however, requires strong cooperation with the local distribution system operator (DSO).

In a review of flexibility options included in local integrated energy system models, Kachirayil et al. find that flexibility is most commonly introduced through sector coupling, particularly of the heat and electricity sectors, implementation of storage capacity, and rarely through demand side management [24]. They further find that sector coupling of the transportation and electricity sectors through EVs is rarely explored in modelling studies despite this constituting one of the most significant flexibility potentials for local systems [25]. Specifically modelling controllable demand, vehicle-to-grid charging and energy storage in an energy community Tostado-Véliz et al. found that optimal scheduling of energy communities could benefit, both, local consumers through reduced operational costs and the surrounding energy system by reducing the need for grid electricity import [26]. Cosutta et al. investigate new energy management strategies for an energy community and find that combined with electricity storage the peak electricity grid demand can be reduced [27], thereby effectively reducing the strain on the surrounding electricity grid.

1.2. Redesigning market structures

Ideally, regulatory and market structures drive energy producers and consumers in realising their flexibility potential. Such structures include tax and tariff structures for energy production and consumption, which again ideally, would incentivise flexible operation to the benefit of the entire energy system. However, previous research indicates that for energy communities this is a topic in need of further attention, even if tangentially related topics have been explored.

Kachirayil et al. argue for the need to assess the market and regulatory constraints in local energy system models [24], e.g., for energy communities, in future work. Furthermore, they find that more studies need to include assessment criteria other than costs and emissions, such as important system characteristics like RE share and energy imports. Backe et al. [20] find that a conflict of interest exists as energy communities naturally seek to optimise operation through increased self-consumption and economic optimisation subject to electricity prices and grid tariffs. This is opposed to an operation based on a wider system perspective, as it is generally not an inherent aim to maximise system-wide benefits (e.g., flexibility) in the operation of an energy community. Hence, Backe et al., argue that price signals and incentives locally should reflect the need for flexibility in the surrounding system, finding that: "*Further research is needed on EC [energy community] market design that ensures the balance between local and global objectives*." [20]. Arriving at a similar conclusion, Stroink et al. find that: "*…it is a necessary precondition that flexibility is incentivised, for example via network tariffs, and that DSOs are obliged to consider flexibility sources as an alternative to grid expansions.*" [21]. Hence, a consensus exists on a need for further research on market and regulatory structures for energy communities.

1.3. Scope and research question

This paper investigates the flexibility potential of an energy community and how such an energy community can operate in conjunction with the surrounding energy system. This is investigated based on energy system modelling where a range of different technical and policy scenarios are explored. A Danish energy community is selected as a case and is used to illustrate the impact of different policy scenarios in different technical energy community configurations.

This study investigates two main research questions:

1. How will different tax and tariff structures affect the operation of an energy community depending on the technologies used in these?

2 *How does the operation fit into a future national energy system based primarily on renewable energy?*

The study presents novel analyses on the unexplored flexibility potential of energy communities under new tax and tariff schemes in different technical system configurations and assesses energy community integration in a surrounding 100% renewable energy system. The study thereby provides policy makers and practitioners with valuable insights into the role and benefits of energy communities for the future design of regulatory and market structures.

2. Methods

Scenarios are modelled and evaluated for the energy community Avedøre Green City based on its 2020 technical system and energy demands as this is the most recent year with complete data availability. There are some plans for the installation of new technologies, but as plans are not finalised these are not included in the Reference Scenario.

This section introduces the case area, the technical and policy scenarios investigated, the assessment criteria applied, and the modelling tool applied for energy system modelling.

2.1. Case area: Avedøre Green City

Avedøre Green City is in the south-western part of the greater Copenhagen area in Denmark. It has approximately 6,000 inhabitants and is at the time of writing the largest energy community in Denmark. It is a predominantly residential area consisting mostly of multi-family housing (apartments) and no local industries, with the largest energy consumers being the local high school and public swimming pool. Hence, the largest energy demands are for heating, general electricity, and transportation. The energy community is modelled based on its 2020 technical system and energy demands, but some fundamental alterations are made. Firstly, no local renewable electricity production is included in the Reference Scenarios, despite a small photovoltaic (PV) capacity being installed in 2020. This allows to clearly distinguish between scenarios with and without renewable electricity production and thereby assess the impact of renewable electricity production. Secondly, plans for the conversion of individually heated households are fully implemented, so that only households connected to a common DH system are included.

Avedøre Green City consists of two separate heating areas with a distance between them of less than 1 km. The two sites are here denoted as Site 1 and Site 2, and as there are no plans to connect the two areas, they are modelled without any heat exchange between them.

Site 1: An area with an existing DH network with a primary supply from the central Copenhagen DH system, supplemented by local backup and peak-load natural gas boilers. The site constitutes approximately 90% of the total heat demand in the energy community.

Site 2: An area without a DH network but with plans of developing a common heat system based on low-temperature DH (30 °C forward temperature) and booster HPs located in individual buildings for boosting the temperature. The site constitutes approximately 10% of the total heat demand.

The heat demand for the buildings that currently have DH is included in the model based on measured data for the annual DH consumption in 2020 incl. network losses. The heat demand in buildings that currently have individual heat supply is estimated via Aalborg University's Heat Atlas [28] with data from the Building and Housing Register (BBR) from 2019. The heat atlas method is described by Grundahl and Nielsen [29] and the update to BBR-data from 2019 is described by Mathiesen et al. [30].

The two sites are assumed to be connected for electricity exchange, and thereby from a modelling perspective, it does not matter whether PV, EVs, or other technologies connected to the electricity grid are in Site 1 or Site 2. The electricity demand for the buildings is the hourly measured electricity demand in 2020.

A schematic diagram of the modelled Reference Scenario can be seen in Fig. 1.

In the system schematic in Fig. 1, the heat exchanger included at Site 1 represents the connection to the central Copenhagen DH system. In Site 2 a combination of a DH boiler, a low-temperature electric heat pump (HP), and booster HPs are used to cover the heat demand. An energyPRO model including all tested technologies and policy schemes for Avedøre Green City is available online [31]. The free demo version of energyPRO is sufficient for accessing the model. Further information on the case area including technical and economic parameters and specific

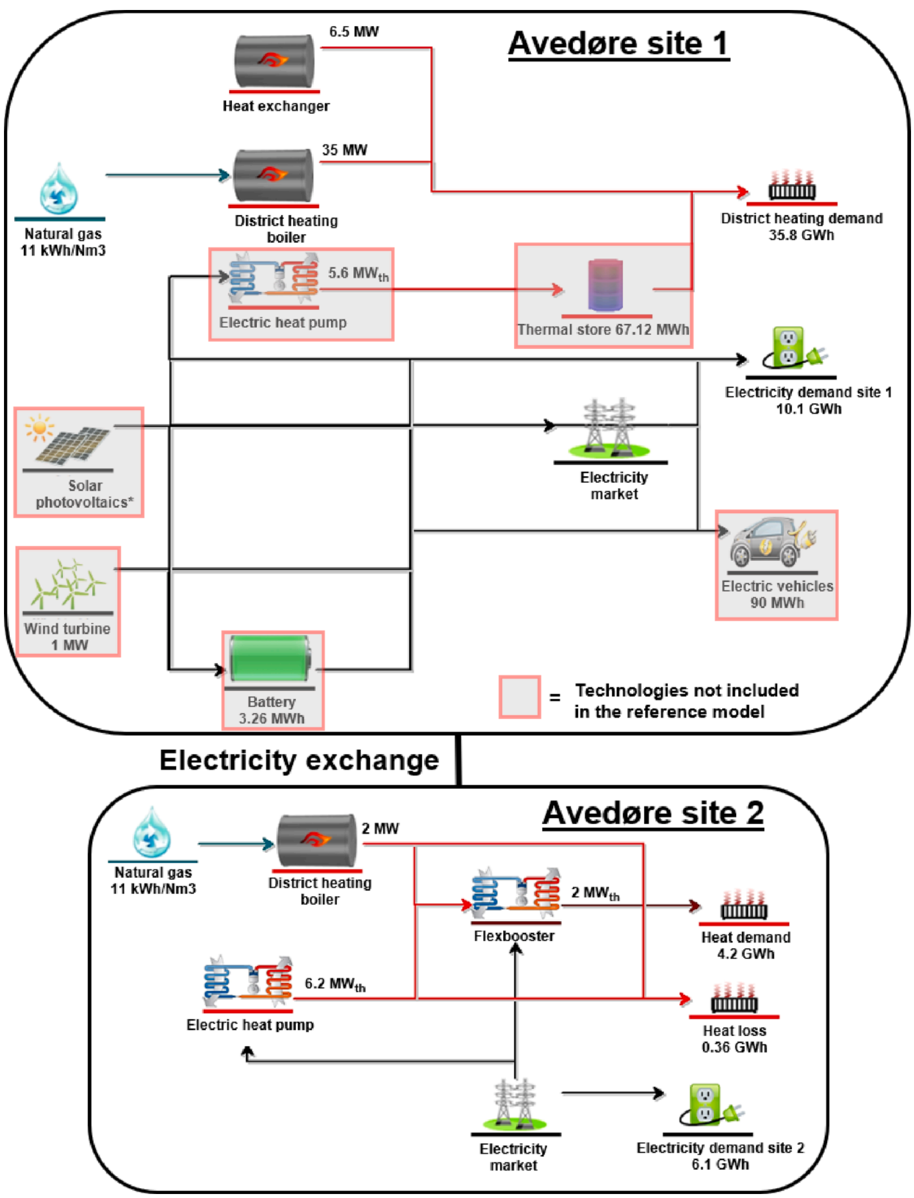

Fig. 1. Avedøre Green City schematic diagram from energyPRO.

heat and electricity profiles is in the Appendix.

2.2. Technical and policy scenarios

A combination of technical and policy scenarios is investigated; an overview of all included scenarios can be seen in Fig. 2. In total, 18 different technical scenarios and six different policy scenarios are modelled, resulting in 108 scenario combinations.

The reference system shown in Fig. 1 is used as a starting point for all technical scenarios. Three main technologies representing flexible consumption are included:

- HP with heat storage in the DH system of Site 1 allows for the efficient conversion of electricity to heat and heat storage allows for flexible operation when it is economically advantageous compared to purchasing heat from the central Copenhagen DH system. Naturally, the HP will have a higher production in periods with higher heat demands mainly during the winter, hence the flexibility potential will be limited in the summer period.
- EVs with smart charging allow for flexible charging. The flexibility potential is subject to the users' driving demand as a limiting factor but is less seasonally dependent than the HP. Vehicle-to-grid charging is not included as an option, as the principle is covered by the battery capacity.
- Batteries for electricity storage are the most flexible technology included as their operation is not correlated to user behaviour or seasonal variations, and instead can be used to balance electricity production and consumption.

Technical Scenarios 1–6 include the above-mentioned flexibility-enabling technologies (an additional HP and thermal storage in Site 1, smart charge EVs, and electricity storage). Technical Scenarios 1.1–6.1 also include VRE generation capacity in the form of PV and a 1 MW wind turbine (WT). Finally, technical Scenarios 1.2–6.2 are aligned to a national 100% RE system to investigate the compatibility and integration of Avedøre Green City in a national RE system. This is done by updating the electricity market price to an electricity price series generated by the 100% RE system and the hourly marginal electricity production cost, along with aligned assumptions on climate and weather data.

In Fig. 3 the daily average electricity production profile can be seen for the included WT and PV panels relative to their total installed capacity. PV has a very distinct daily profile, both, during the summer and winter periods, but on average the production is higher during the summer period. Wind power does not have a distinct daily profile as production occurs both during the day and night period. On a seasonal basis, however, production on average is higher during the winter.

As mentioned, a fixed capacity of 1 MW of wind power is included as that is the expected capacity to be installed based on concrete local plans. The installed PV capacity is varied per scenario depending on what technical system it is installed into. This mainly depends on how large the electricity demand is, how flexible the demand is, and the extent to which storage options are available. To account for this, a method was devised to determine what PV capacity to install in the different technical scenarios. It is the ambition that VRE capacity is installed mainly to supply a local demand as opposed to installation with the primary purpose of exporting electricity. Therefore, an analysis was conducted for Scenarios 1–6 with serial calculations of installed PV capacity in 0.5 MW intervals from 0 MW to 15 MW. For each interval, the additional electricity production and electricity export was calculated, resulting in a marginal electricity export per installed capacity. The selected installed capacity is then the largest possible capacity that does not result in more than 50% marginal electricity export, i.e., when additional capacity is mainly for export rather than local consumption. The outcome of this analysis can be seen in Fig. 4 for each scenario.

The resulting installed PV capacity per scenario can be seen in Table 1. A general tendency observed is that as the electricity demand increases (and more flexible electricity-consuming technologies are installed), the potential for installed PV capacity increases concurrently.

A range of tax and tariff structures are proposed to investigate how the different technical scenarios respond to such new market structures as incentives for flexibility. Electricity grid tariffs in Denmark are subject to three key principles established in the Danish Electricity Supply Act [32] and the European Internal Electricity Market Regulation [33] which need to be embedded in the design of electricity grid tariffs:

1. *Tariffs need to be based on fair (cost-reflective), objective, and non-discriminating criteria.*
2. *Tariffs need to provide suitable incentives in the short and long term to ensure an efficient electricity system.*
3. *Tariffs need to be transparent and understandable.*

The above principles serve as guiding principles for the design of proposed new tariff schemes. Electricity taxes are not inherently subject to the same principles as grid tariffs, as they by nature are not intended to cover a specific system cost, but rather are fiscal or intended to affect behaviour. The tax payment could also just as well incentivise and reward flexibility and operation that benefits the surrounding energy system – it is just not currently embedded in the Danish tax payment structure. The following policy Scenarios A-F are explored in this study:

A. In a 2020 policy scenario, all taxes and grid tariffs are included as they were in Denmark in 2020. In Scenario A all applicable restrictions for energy communities are applied, which, e.g., means that self-consumption within the energy community is not exempt from tax and tariff payments.
B. In a net-settlement scenario, all electricity production within the energy community used for self-consumption is not subject to taxes and grid tariffs.
C. In a variable time-of-use (TOU) scenario, taxes and grid tariff rates are based on a fixed hourly schedule with peak and low-load periods. Peak load periods occur every day from 17.00 to 20.00 from the 1st of October to the 1st of May, and the rest of the year is designated as low load periods. This structure is implemented for the Transmission system operator (TSO) network tariff and the electricity tax, while the DSO grid tariff is unchanged, as it already follows this structure. The system and balancing tariffs remain non-variable.
D. In a dynamic taxes and tariffs scenario, electricity taxes and grid tariffs fluctuate depending on how much VRE is in the national electricity grid on an hourly basis. Thus, there is not a static hourly schedule for taxes and tariff rates, instead, it will vary from hour to hour. As in C, only the electricity tax and the network tariff for the TSO are changed. The DSO tariff is not changed, as this is mostly dependent on the state of the local grid rather than the national RE.
E. In a capacity payment scenario, DSO and TSO grid tariffs are partly converted to a capacity payment. In this scenario, it is chosen to convert 50% of the TSO network payment and 75% of the DSO grid tariff payment to capacity payment based on peak electricity consumption throughout the year.
F. Implementation of both Scenarios C and E.

The modelled policy scenarios do not cover all possible tax and tariff structures but represent a sample of the ongoing discussions on options for restructuring tax and tariff payments.

The proposed tax and tariff structures generally adhere to the key principles for electricity market design, i.e., by being objective and non-discriminating in the sense that producers and consumers are subject to the same rates, determining the exact tariff rate reflecting the actual costs incurred by the DSO and TSO is difficult. Furthermore, these new tax and tariff structures are inevitably more complicated than the existing structures based mainly on volumetric electricity consumption at a fixed rate and are thereby arguably not as easily understood by the

Technical scenarios \ Policy scenarios		A **Current policies** - All taxes and tariffs at 2020 level	B **Net settlement** - Tax and tariff exemption (self-consumption)	C **Variable tax and tariff rates** - Time of use (TOU) tax and tariffs	D **Dynamic tax and tariff rates** - Variable tax and tariffs based on RE share	E **Capacity payment** - 50% (TSO) and 75% (DSO) capacity payment	F **Capacity tariff and TOU tax/tariffs** - 50%/75% capacity payment and TOU tax/tariffs
1	**Reference system** - No changes in DH system - Booster HP for areas outside DH	1A	1B	1C	1D	1E	1F
1.1	- 1 MW WT and 3.3 MW PV capacity	1.1A	1.1B	1.1C	1.1D	1.1E	1.1F
1.2	- As 1.1 aligned to 2045 national scenario	1.2A	1.2B	1.2C	1.2D	1.2E	1.2F
2	**HP and thermal storage in DH** - Electrical HP installed in DH system	2A	2B	2C	2D	2E	2F
2.1	- 1 MW WT and 4.7 MW PV capacity	2.1A	2.1B	2.1C	2.1D	2.1E	2.1F
2.2	- As 2.1 aligned to 2045 national scenario	2.2A	2.2B	2.2C	2.2D	2.2E	2.2F
3	**Smart charge EVs** - 2,000 smart charge EVs	3A	3B	3C	3D	3E	3F
3.1	- 1 MW WT and 3.5 MW PV capacity	3.1A	3.1B	3.1C	3.1D	3.1E	3.1F
3.2	- As 3.1 aligned to 2045 national scenario	3.2A	3.2B	3.2C	3.2D	3.2E	3.2F
4	**Elec. storage (battery)** - Li-ion batteries installed for storage	4A	4B	4C	4D	4E	4F
4.1	- 1 MW WT and 3.7 MW PV capacity	4.1A	4.1B	4.1C	4.1D	4.1E	4.1F
4.2	- As 4.1 aligned to 2045 national scenario	4.2A	4.2B	4.2C	4.2D	4.2E	4.2F
5	**HP in DH and EVs** - Electrical HP installed in DH system - 2,000 smart charge EVs	5A	5B	5C	5D	5E	5F
5.1	- 1 MW WT and 5.0 MW PV capacity	5.1A	5.1B	5.1C	5.1D	5.1E	5.1F
5.2	- As 5.1 aligned to 2045 national scenario	5.2A	5.2B	5.2C	5.2D	5.2E	5.2F
6	**HP in DH, EVs and elec. storage** - Electrical HP installed in DH system - 2,000 smart charge EVs - Li-ion batteries installed for storage	6A	6B	6C	6D	6E	6F
6.1	- 1 MW WT and 5.5 MW PV capacity	6.1A	6.1B	6.1C	6.1D	6.1E	6.1F
6.2	- As 6.1 aligned to 2045 national scenario	6.2A	6.2B	6.2C	6.2D	6.2E	6.2F

Fig. 2. Technical and policy scenarios modelled.

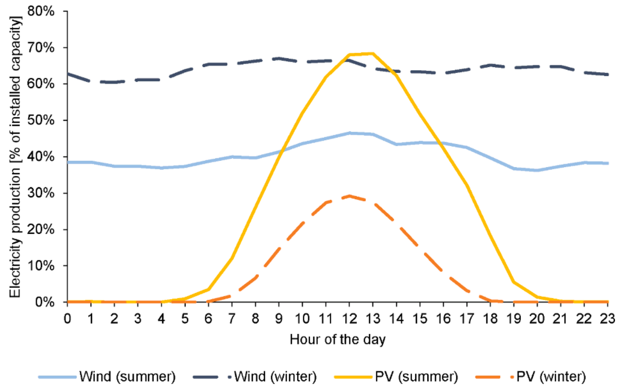

Fig. 3. Daily average PV and wind electricity production profile. The summer period is defined as the period from April to October and the winter period is from October to April.

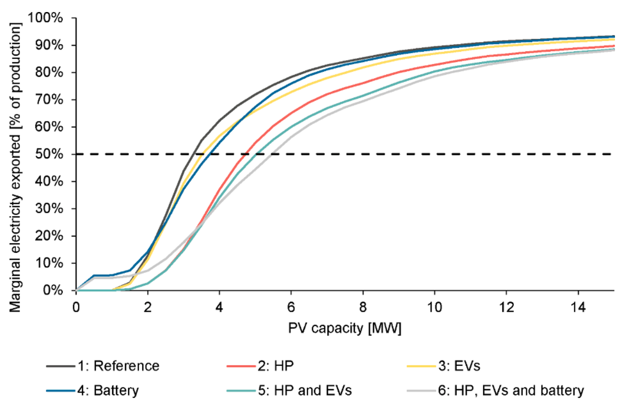

Fig. 4. Determining PV capacity based on marginal electricity export.

Table 1
Installed PV capacity per scenario.

Scenario	1: Reference	2: HP	3: EVs	4: Battery	5: HP and EVs	6: HP, EVs and battery
Installed PV capacity	3.3 MW	4.7 MW	3.5 MW	3.7 MW	5.0 MW	5.5 MW

regular electricity consumer. Further information on the modelled policy scenarios including the specific tax and tariff rates applied can be found in the Appendix.

2.3. Assessment criteria

The primary focus of the modelling is to investigate how an energy community interacts with the surrounding energy system and electricity grid in Denmark. Hence, the focus is on the exchange of electricity to and from the energy community, and therefore the following measuring points will be the focus of the analysis:

- Annual max electricity import (MW)
- Total annual electricity import (MWh/year)
- Annual max electricity export (MW)
- Total annual electricity export (MWh)
- Electricity purchase price (EUR/MWh)

The maximum import and export of electricity for one hour throughout the year indicate how much the surrounding electricity grid needs to be expanded to accommodate the operation of the energy community. Thus, the maximum import and export of electricity throughout the year is a proxy for the expected effect on the investment costs in the surrounding electricity grid. It is expected that these maximum values are the most important factors in identifying the effects on the surrounding electricity system due to the fixed costs correlated to the installed maximum capacity of the grid connection to the energy community.

The annual energy import and export provides an indication of the electricity grid usage over the course of the year, which affects the expected operating costs for the electricity grid, mainly related to the grid loss. This is also a proxy and cannot necessarily be used one-to-one to calculate a real cost change in the surrounding network.

Payment for electricity from the electricity market, in this case, Nord Pool Spot, shows whether a changed tax or tariff structure can force the energy community to shift electricity consumption to times when the electricity price on the market is higher. Energy communities can in principle also participate in ancillary and balancing markets, though this is not included in this study.

2.4. Modelling tool

Avedøre Green City is modelled with the software tool energyPRO [34], an energy system modelling tool for techno-economic analysis mainly for local energy systems, generally emphasising the operation of common energy systems such as DH. EnergyPRO allows for the modelling of all relevant energy demands in timesteps for one or multiple-year periods - for this study hourly timesteps and a one-year calculation period are applied. Energy conversion units, energy storages, fuels, and electricity markets can be included in the models, including all related fixed and variable costs, after which energyPRO will optimise the operation of technologies to fulfil demands at the lowest total system cost for the modelled system. EnergyPRO furthermore provides the option of user-defined costs, including taxes and tariffs, and thus the opportunity to test different tax and tariff structures. EnergyPRO is widely used in scientific literature, being mentioned in 168 journal articles where it has been applied extensively for systemic analyses of DH, and to a lesser extent, for holistic energy system analysis of urban areas [34]. Specifically, energyPRO has also been instrumental in analyses of how subsidies [35,36], taxes [37–39] and market price levels [40] promote investments in flexible technologies as well as the flexible operation of these.

EnergyPRO allows for the use of a built-in analytical simulation approach or the use of an external solver [41]. In this study, the Mixed-Integer Linear Optimisation solver, Gurobi, is utilised in energyPRO.

In this study, energyPRO is used for the economic optimisation of energy balances for the energy community. Investment costs or annual fixed costs are not included in the analyses, as the focus is solely on changes in operation patterns. This also means that the analyses cannot be used to identify whether specific technology investments are advantageous for the energy community in a business-economic sense, but only to identify what effects the tariff structures and technologies will have on the operation of the energy community itself. The analyses also only consider the minimization of the total variable costs for the energy community, and the analyses thus do not relate to how individual citizens are affected financially. This will depend on the method of distribution of costs in the energy community. However, it can be assumed that an overall improved economy of the energy community would benefit the participating consumers.

3. Results

This section presents the results from the modelling of technical and policy scenarios for Avedøre Green city, focusing on how the production and consumption of electricity are shifted in different technical system configurations under differing tax and tariff schemes. Secondly, results are presented on the distribution of costs to illustrate the economic impact of the applied tax and tariff schemes, and finally, the operation of the energy community is compared to the operation in a surrounding 100% renewable national energy system.

3.1. Electricity consumption profiles

To present the effect of different policy scenarios in different technical scenarios, daily average electricity consumption profiles are presented alongside annual load duration curves. The daily average consumption profiles provide an overview of the average effect throughout the year but do not show any seasonal or weekend variations. In the load duration curves energy demands for all hours of the year are sorted from highest to lowest, thus providing an overview of annual variations. Results are only shown for Scenarios 2 and 2.1 (HP + storage), 3 and 3.1 (EVs), and 4 and 4.1 (battery) to illustrate the effect of implementing different technologies in the energy community. Results for the complete range of scenarios are included in the Appendix.

In Fig. 5 daily average profiles and load duration curves for the Reference Scenario and technical Scenarios 2 and 2.1 can be seen. The Reference Scenario has limited flexibility potential, consisting only of the central HP in Site 2, and therefore average profiles and load duration curves do not vary significantly across the different policy scenarios. In scenarios 2 and 2.1 a central HP and thermal storage are installed in Site 1, supplementing the heat delivery from the Central Copenhagen DH system.

This HP consumes approximately 7.5 GWh of electricity annually, thus increasing the yearly electricity demand by 42%, which, together with the thermal storage, adds significant flexibility potential to the energy community. This can be seen quite clearly in Fig. 5 for Scenario 2, showing an average increase in electricity consumption, but also a smoothing of the curve due to the relatively stable production of the HP. It can further be seen that the introduction of capacity payments in Scenarios E and F causes the model to reduce the peak load during hours 15 and 16 to reduce the peak payment. In Scenario 2.1 local VRE production from wind power and PV is introduced, which mostly influences operation in Scenario B where the energy community is allowed net settlement of self-consumption. This causes the system to shift electricity consumption from the night to the day to align better with the electricity production from PV. The load duration curve for Scenario 2 shows a peak electricity consumption of 5.26 MW for most scenarios. However, the electricity consumption is only above 5 MW for one hour annually. The effect of capacity payments can be seen quite clearly, smoothing the electricity consumption to a peak consumption of 3.8 MW for approximately 1,900 h annually. In Scenario 2.1 with local VRE production, the peak electricity consumption is higher for Scenarios E and F with capacity payments compared to Scenario 2. This is because the capacity payment is only assumed for the import of electricity, and hence local VRE production can be used internally without incurring a capacity payment.

Fig. 6 shows daily average profiles and load duration curves for technical Scenarios 3 and 3.1. In these scenarios EVs with smart charging are introduced, with an annual electricity demand of 6.3 GWh, increasing the yearly electricity demand by 35%. As can be seen in the daily average profiles for both Scenario 3 and 3.1, the charging mostly occurs during the night when electricity prices on average are lower. It can also be seen that capacity payments in Scenarios E and F, and to a lesser extent the dynamic tariff structure in Scenario D, reduce the night-time peak consumption for EVs. This indicates that tax and tariff schemes have a significant influence on electricity consumption in EVs as it is a relatively flexible form of demand. In Scenario 3.1 local VRE production is introduced, which mainly influences Scenario B where net settlement is allowed, causing some electricity consumption to be shifted from night-time to daytime. In the load duration curve for Scenario 3 a large increase in peak electricity consumption is observed for Scenarios A-D due to the EV charging. The capacity payments in Scenario E and F again reduce the electricity consumption and instead distribute charging (electricity consumption) over a longer period achieving a flatter electricity consumption curve. As in scenarios 2 and 2.1, the

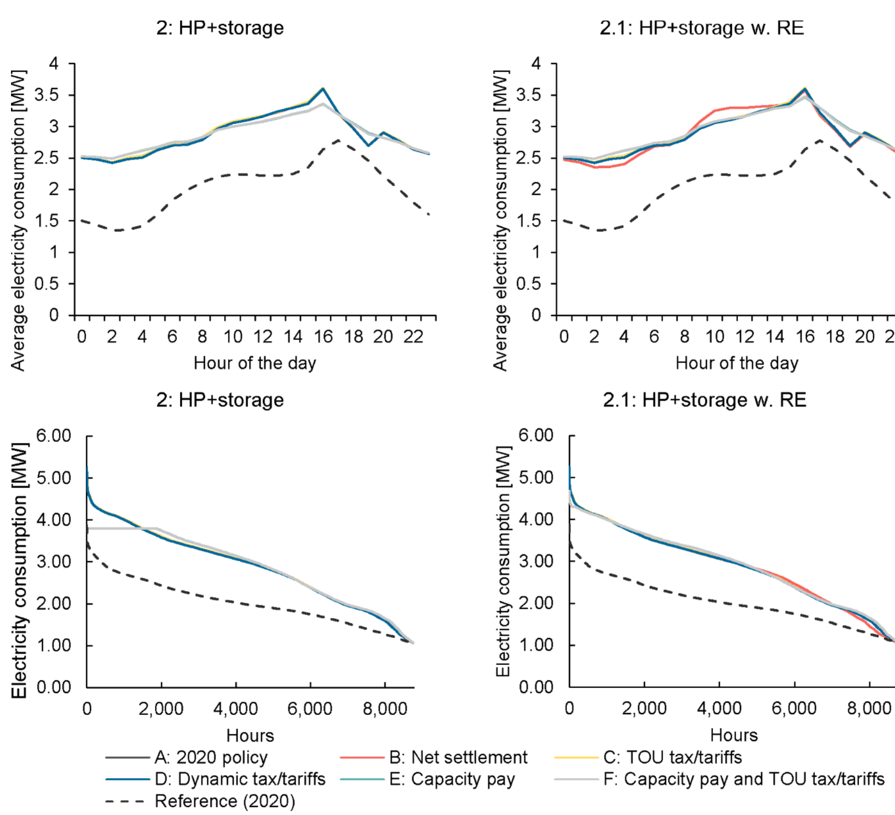

Fig. 5. Daily average profiles and load duration curves for technical Scenarios 2 and 2.1.

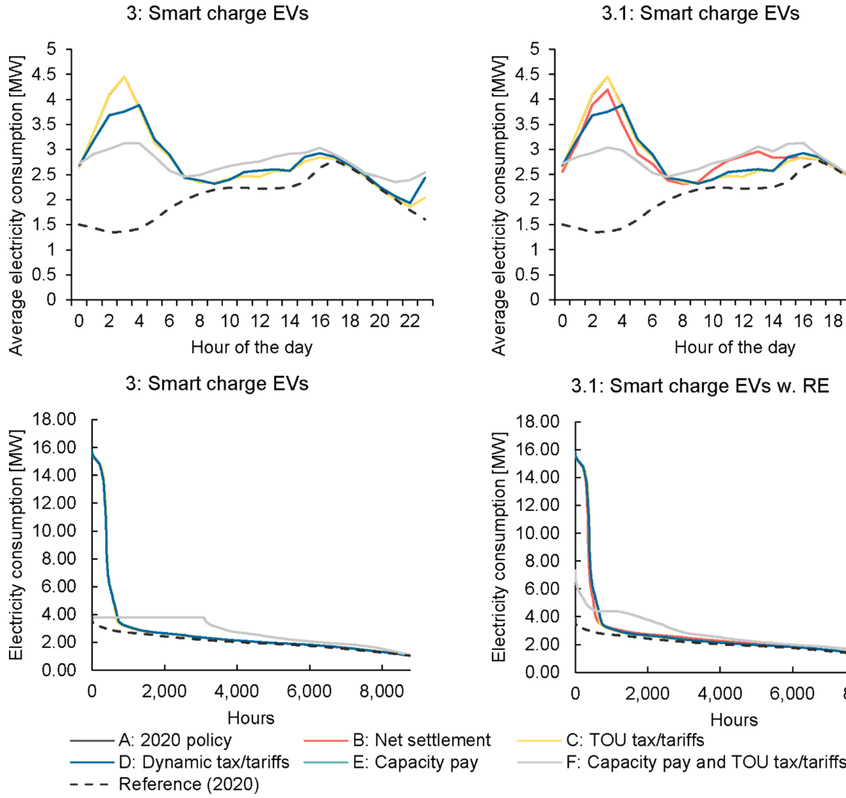

Fig. 6. Daily average profiles and load duration curves for technical Scenarios 3 and 3.1.

addition of VRE increases the peak consumption for Scenarios E and F with capacity payments as only electricity imports are subject to capacity payments.

Fig. 7 shows daily average profiles and load duration curves for technical Scenarios 4 and 4.1. In these scenarios, batteries are implemented as a flexibility measure, and contrary to e.g., HP or EVs, these

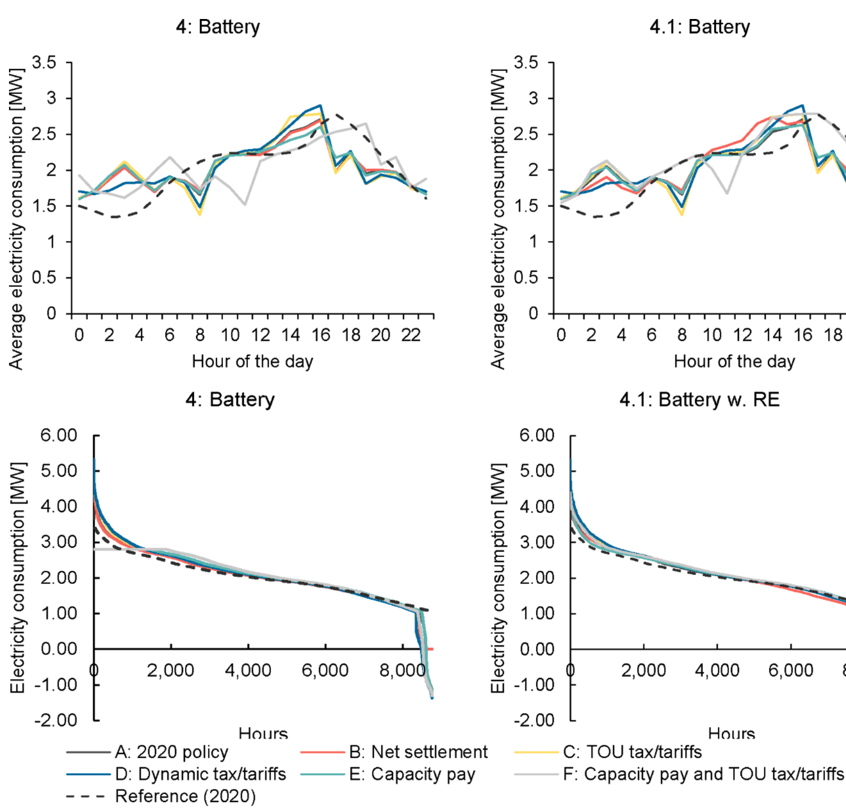

Fig. 7. Daily average profiles and load duration curves for technical Scenarios 4 and 4.1.

are not limited by demand profiles or seasonal variations. In the daily average profiles, electricity for charging the batteries is included in the hourly consumption, while electricity from discharging of batteries is subtracted from the hourly consumption. The batteries are used to move inflexible electricity demand compared to the reference. Increased electricity consumption can be observed during the night and at midday, and concurrently, reduced electricity consumption during the afternoon and evening. In the load duration curves the peak electricity consumption increases compared to the reference, and in some hours because of electricity export from the batteries the electricity consumption is negative. This does not occur in Scenario B with net settlement as it is incentivised to use the batteries for self-consumption rather than to purchase electricity only to later sell the same electricity back to the grid.

3.2. Annual electricity grid exchange

The annual peak electricity import per scenario for the energy community as a whole can be seen in Fig. 8. In Scenario 1: Reference, the peak electricity import is 3.87 MW, of which 3.5 MW is the measured electricity demand occurring between 17.00 and 18.00 on December 24th. The remaining 0.37 MW is for electric HPs in Site 2 operating at the same hour. As can be seen for Scenario 1.1: Reference w. VRE, the addition of local VRE capacity reduces the peak electricity import due to a coinciding production of 0.96 MW from the installed local WT, causing the peak electricity import to occur during a different hour. It can further be seen from Fig. 8 that scenarios with EVs result in significantly increased peak electricity import. This can mostly be negated by capacity payments which influence the charging strategy of the EVs distributing charging more evenly throughout the year. A general takeaway for capacity payments is that they are capable of reducing the peak electricity import in systems with flexible demands or batteries, but for systems without these flexibility options, they have no operational effect.

Fig. 9 shows the annual electricity import to the energy community. A general observation is that implementing local VRE capacity naturally reduces the annual electricity import. The implementation of a HP combined with heat storage causes the largest increase in electricity import, followed by the EVs, and a slight increase from the installation of batteries. The increased import from batteries is caused by the losses during charging and discharging. The exception to this is when net settlement is combined with batteries: then the batteries will seek to limit grid imports and maximise self-consumption. In general, the tested tax and tariff schemes have less of an impact on the annual import of electricity than what was seen for the peak electricity import in Fig. 8.

The annual peak electricity export per scenario can be seen in Fig. 10. Naturally, there is only export of electricity when local VRE production is included in the scenarios, or when batteries are included. The peak electricity export generally increases in scenarios with higher installed VRE production capacity, which varies per scenario as described in the applied method for determining installed PV capacity in Section 2.2. Batteries generally increase the peak export as they are occasionally used to purchase electricity and sell it back to the grid later as part of an economic optimisation of the system operation. However, this tendency does not occur when a net settlement tax and tariff structure is introduced, as the batteries and the system, in general, seek to increase self-consumption. In scenarios with significant flexibility potential, i.e., Scenarios 3.1, 5.1, and 6.1, electricity export is nearly or fully avoided when net settlement is allowed. The dynamic tax and tariff structure has a similar effect of reducing peak electricity export, however, less pronounced.

Fig. 11 shows the annual electricity export per scenario. As was the case for the peak electricity export, only scenarios that include local VRE production or batteries have any export of electricity. Many of the same observations as in Fig. 10 can be made, however, it seems the effect of the dynamic tariff structure on reducing the annual export of electricity is less pronounced than it is for reducing the peak electricity exported. It is also seen that from scenarios E and F with capacity payments the annual export of electricity is reduced. This is a result of the more distributed consumption and charging patterns, allowing the energy community to utilise local VRE production to a larger extent, thus reducing exports. As was seen for peak electricity exports, net settlement reduces or even fully eliminates electricity export due to the increased economic incentive for self-consumption.

The average electricity purchase price per scenario seen in Fig. 12 indicates the extent to which the energy community is able or required to shift consumption to periods with lower (or higher) electricity prices. The cost shown is only the raw electricity purchase price, i.e., without including electricity taxes or grid tariffs. It is seen that for the Reference Scenario without significant flexibility options the average purchase price is the highest compared to the other technical scenarios, and unchanged across different tax and tariff schemes. Scenarios that include EVs generally have the lowest average electricity purchase prices due to the high flexibility of EV charging and thereby ability to target low price

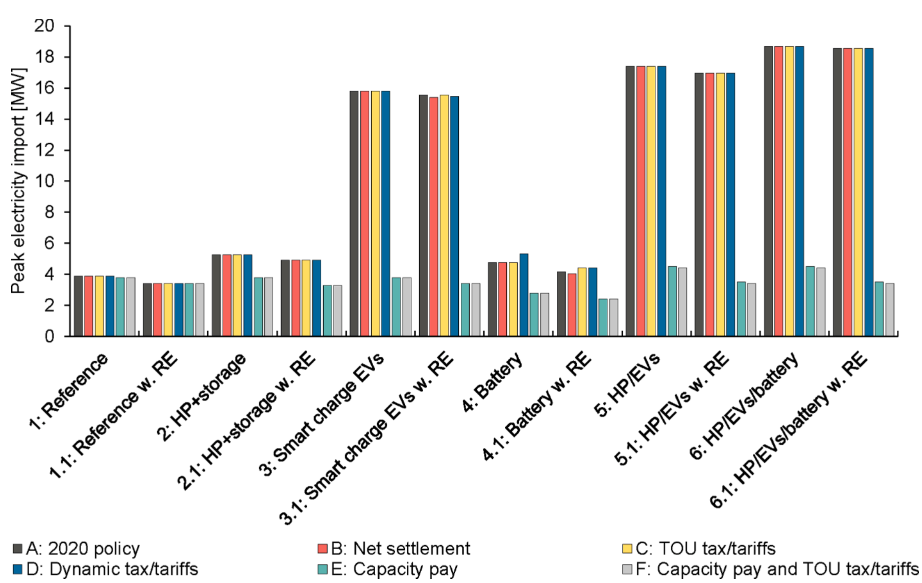

Fig. 8. Peak electricity import per scenario.

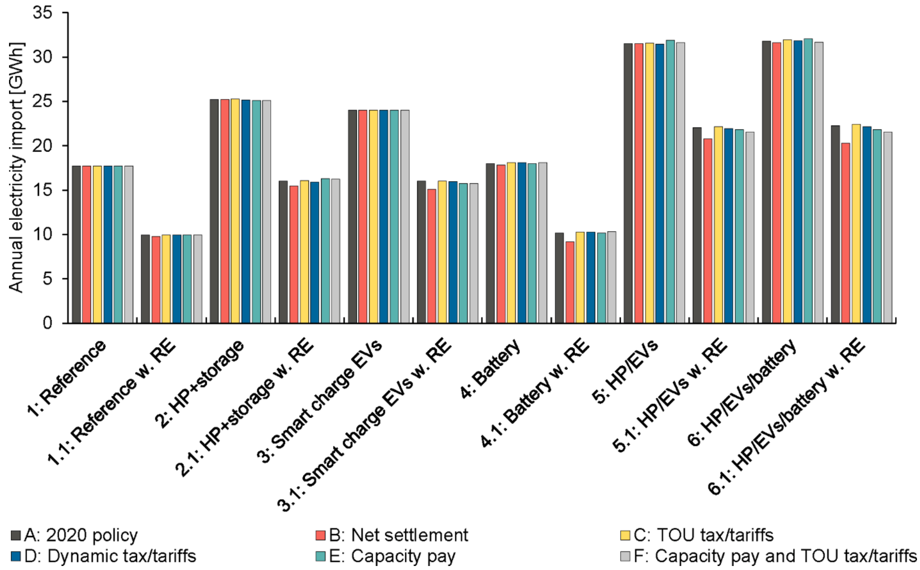

Fig. 9. Annual electricity import per scenario.

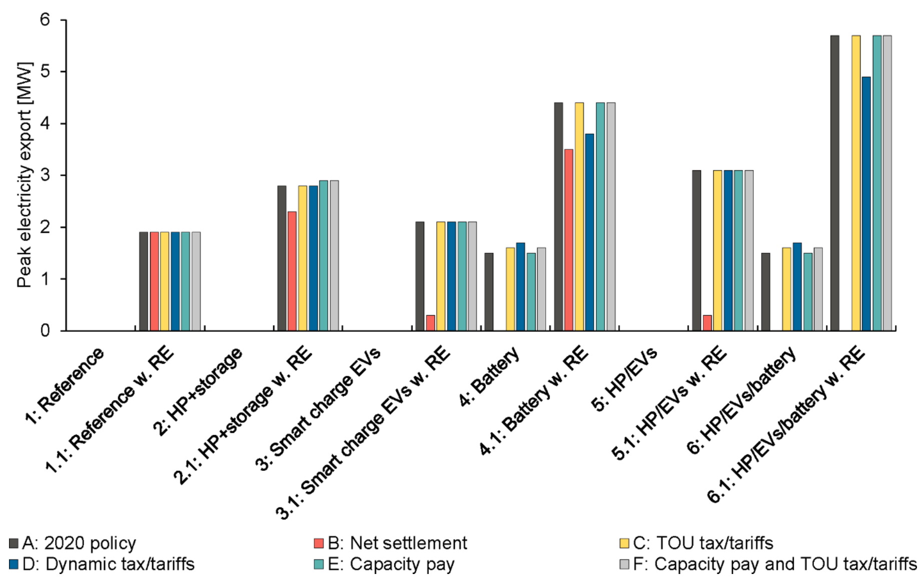

Fig. 10. Peak electricity export per scenario.

periods. Scenarios with local VRE production generally have higher average electricity purchase prices as a smaller volume of electricity is purchased from the electricity market. Because local VRE production often coincides with low electricity price periods the average purchase price increases. Capacity payments generally result in a higher average purchase price, as electricity purchase is distributed across longer periods, as was seen in the duration curves presented in Section 3.1.

3.3. Renewable energy system integration

This section correlates the operation of Avedøre Green City energy community to a future 100% RE system, specifically the Danish Society of Engineers (IDA) 2045 Climate Response scenario for Denmark [42,43]. IDA Climate Response 2045 (IDA2045) is an energy system scenario for Denmark based primarily on energy production from offshore WTs, onshore WTs, and PV, supplemented by biomass and biogas where needed [44]. IDA2045 is a scenario simulated based on an aggregation of all types of technologies independently of geographic location, using the EnergyPLAN model [45]. Furthermore, the operation of the national energy system is based on principles limiting fuel consumption, while the operation of the energy community is based on business economic optimisation. Hence, observed local operation patterns e.g., for an energy community, can differ from the operation expected at an aggregated national level. Comparing the operation of Avedøre Green City thereby indicates what tax and tariff scenario likely best supports a future RE system.

To compare the operation of technologies in the national scenario and the energy community several changes are made to the model to align assumptions, these include: an updated electricity market price, adjusting the dynamic tariffs, and aligning weather data for heat demands, PV, and WT production. The updated electricity price is generated based on the hourly marginal electricity production cost and hence indicates how the surrounding national energy system would influence the operation of a local energy community. To see the impact on operation per technology this section focuses on Scenarios 2.1 (HP with thermal storage), 3.1 (EVs), and 4.1 (batteries). The adjusted versions of the scenarios aligned to IDA2045 are designated as Scenarios 2.2, 3.2, and 4.2.

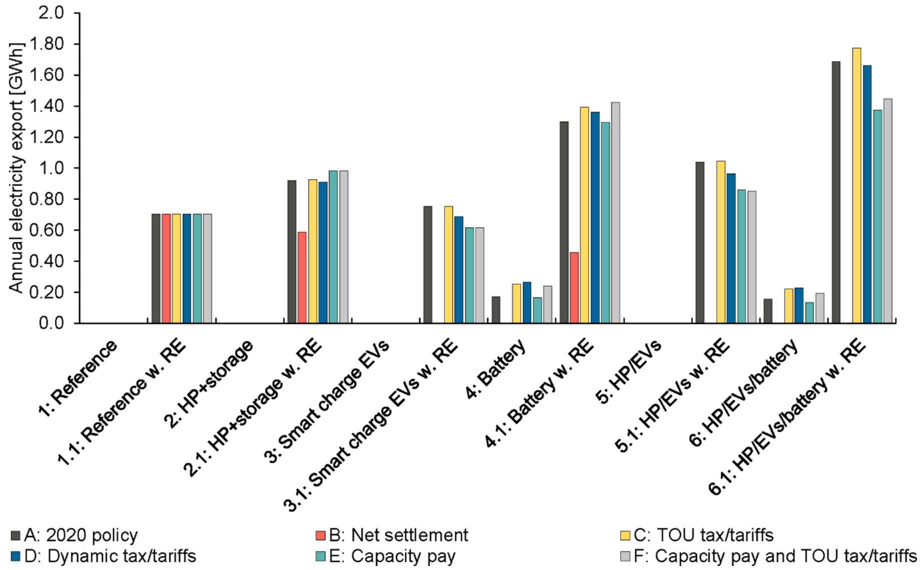

Fig. 11. Annual electricity export per scenario.

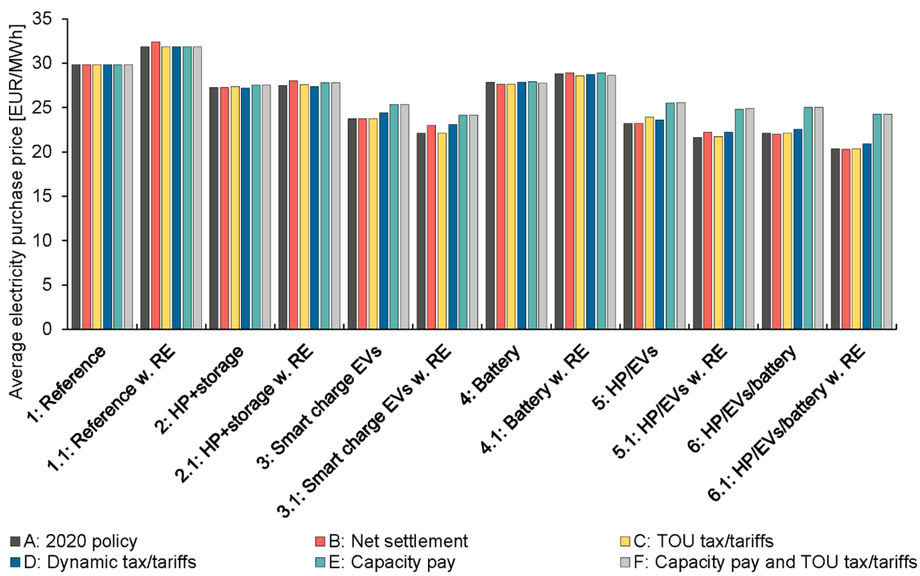

Fig. 12. Average electricity purchase price per scenario.

The operation of HPs is compared across the different tax and tariff scenarios and the IDA2045 scenario in Fig. 13. Only HPs based on low-temperature sources e.g., air or sea water are included from the IDA2045 scenario, as HPs based on high-temperature excess heat have different operation patterns. The installed HP capacity in the IDA2045 scenario is relatively high, resulting in the HPs only having 1,060 full load hours, compared to 3,100–3,200 in Avedøre Green City without capacity payments, and approximately 3,800 with capacity payments. The large installed capacity is mainly a result of a wish for large flexibility on a year-to-year basis, but to better compare operations, an adjusted version of the IDA2045 scenario with a lower HP capacity is developed. This adjusted scenario, IDA (adjusted), is produced by gradually decreasing the installed capacity until the HPs have about 3,500 full load hours. It is seen from the load duration curves in Fig. 13 that all scenarios without capacity payments are relatively close to the adjusted IDA2045 scenario. Scenarios 2.2E and 2.2F in which capacity payments are introduced have a generally smoother duration curve due to the more distributed HP operation, contributing to a lower peak load on the electricity grid at the cost of reduced flexibility in operation.

In Fig. 14 duration curves can be seen for EV charging in Avedøre Green City compared to the duration curve for EV charging in the IDA2045 scenario. Generally, the duration curve for the IDA2045 scenario is higher than the duration curves for Avedøre Green City, i.e., the installed charging capacity is utilised more throughout the year rather than only in peak periods. This is a result of a (relatively) lower installed charging capacity in the IDA2045 scenario at 6 GW for 3.3 million EVs, equal to 1.82 kW per EV. This is significantly lower than the assumed 7 kW per EV in Avedøre Green City. To make a more comparable scenario also for EVs, the IDA2045 scenario is again adjusted, increasing the EV charging capacity to 7 kW per EV.

A general observation from the duration curves in Fig. 14 is that the charging of EVs occurs more evenly throughout the year in the IDA2045 scenario compared to charging in Avedøre Green City. However, the scenarios with capacity payments resemble the charging pattern observed nationally better due to the more distributed charging of EVs. It can also be seen that for the national scenarios peak charging occurs for relatively few hours of the year, resembling the charging seen for scenarios in Avedøre Green City without capacity payments. As it was

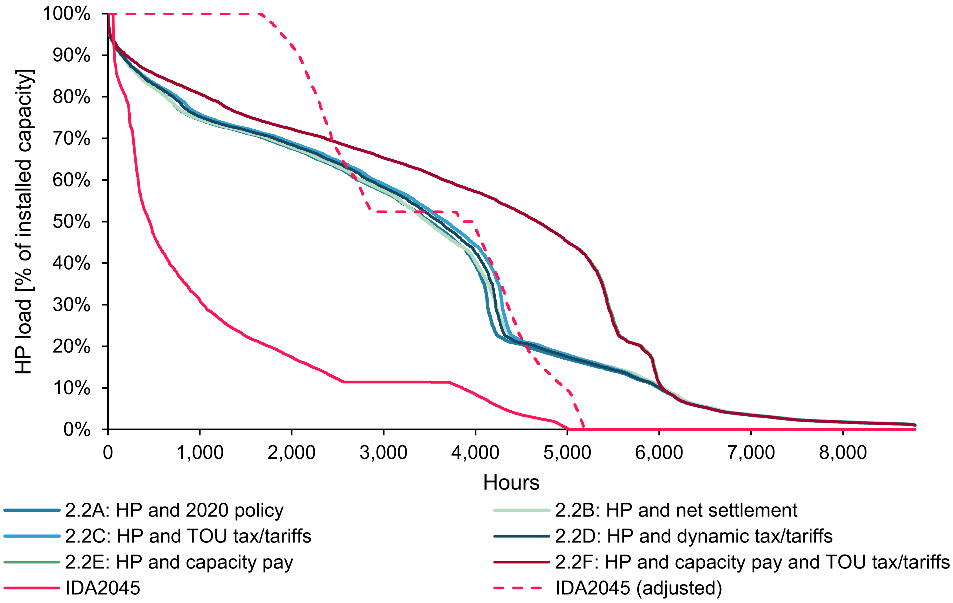

Fig. 13. HP load duration curve comparison for Avedøre Green City and IDA2045 scenarios.

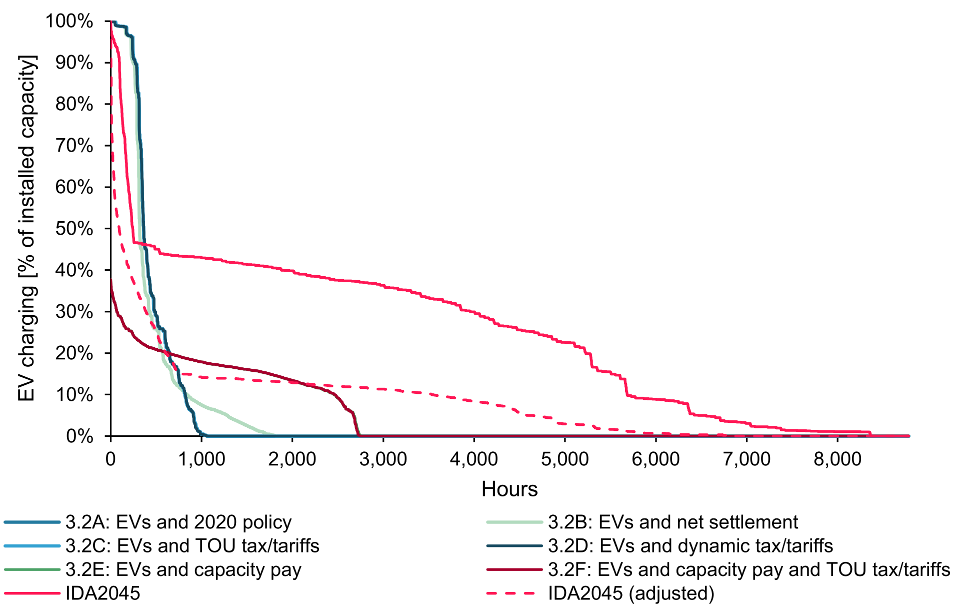

Fig. 14. EV charging duration curve comparison for Avedøre Green City and IDA2045 scenarios.

seen for the HP operation in Fig. 13, capacity payments smoothen the EV charging throughout the year, resulting in a lower peak load of the electricity grid, at the cost of reduced flexibility.

4. Discussion

If energy communities are to be subject to special tax and tariff schemes, energy communities also need to provide concrete system-wide benefits (e.g., flexibility or efficiency improvements) that would not otherwise be realised [11]. New tax and tariff structures were found to incentivise operation that benefits, both, the surrounding electricity grid and in a broader sense, the surrounding energy system. However, without radical changes to the tax and tariff design, the effect is relatively limited. E.g., simply switching to a fixed TOU tax and tariff structure does not significantly incentivise flexible operation or limit grid imports. However, introducing capacity payments appears to provide an incentive to limit peak grid imports caused by EV charging and could be considered for this purpose. At the same time, capacity payments have a counterproductive effect on the flexibility of the energy community as they incentivise distributed consumption, and hence in designing such measures, the need for flexibility must be considered alongside the need for limiting peak grid electricity demand.

Studies conducted specifically for the DH sector focusing on the operation of power-to-heat technologies have shown similar results. Bergaentzlé et al. modelled the operation of power-to-heat technologies in a DH system under three alternative grid tariff structures, concluding that traditional volumetric tariffs are an impeding factor to flexible operation, and that grid tariffs represent an underutilized lever for realising the flexibility and decarbonising energy systems [46]. Johannsen et al. [38] and Østergaard and Andersen [37] also investigated operation of power-to-heat technologies in DH under new grid tariff structures and variable taxes, respectively, finding some but limited potential flexibility. The studies did not consider flexibility outside of the heating sector, such as the potential flexibility from EVs or batteries as included in this study, and flexibility was only assessed in terms of operation of power-to-heat technologies, and not as grid and energy system effects.

The modelling for this study assumed that the energy community can operate in the best interest of the energy community as a whole (in a business economic sense), e.g., by limiting peak import and thereby minimising capacity payments. Individuals may choose to optimise expenses for themselves rather than as a community e.g. when charging EVs, so the results may not be easily transferable, or additional measures may be needed to realise the estimated potential. It is, however, an embedded part of energy communities that they should emphasise environmental, economic and social community benefits for local members, rather than profit maximisation [47], and hence optimising benefits for the community as a whole is well-aligned to such perspectives.

Due to the study being limited to a single case study and country, the results are naturally not necessarily valid for other energy communities with other technical system configurations or in countries with different regulatory setups or cost structures. It should furthermore be noted that not all possible tax and tariff schemes were modelled; future studies could investigate additional options, or further assess how to allocate a capacity payment combined with a volumetric energy component for DSO and TSO tariffs. This study evaluated the impact of the energy community on the surrounding electricity grid through correlated parameters but not direct electricity grid modelling. Hence, the results of the study should be considered as indications of the impact on the electricity grid and not as concrete metrics of how the electricity grid is impacted, neither in technical nor economic terms. The use of peak shaving effects for the purpose of estimating grid strain is however applied in existing studies of energy communities, focusing on modelling effects of energy storage [27,48,49]. Finally, the modelling of EVs did not include vehicle-to-grid charging, which could potentially be a significant source of flexibility in the future [50]. This would likely require further considerations on the design of tax and tariff schemes, which could be explored in future studies.

5. Conclusion

It is found that local renewable electricity production in addition to a local flexibility potential, either in the form of flexible demands or energy storage capacity, is a prerequisite for energy communities to provide any grid or energy system benefits. The addition of HPs in DH and EVs both increase the electricity peak demand, but the effect is most pronounced for EVs due to the higher charging capacity. Both technologies will target low-price periods and thus combining the two technologies effectively exacerbates the effect. A capacity payment to some extent negates this effect by encouraging temporally more distributed consumption. The addition of batteries results in a larger annual electricity demand and a higher peak demand due to the batteries charging during hours of low electricity prices, coinciding with HP operation and EV charging.

Introducing a capacity payment causes the batteries to be used to reduce the electricity peak demand; however, the effect is most pronounced in scenarios with mainly inflexible electricity demand. Net-metering of taxes and grid tariffs from the energy community increases the self-consumption of wind and solar energy, reducing annual export and import of electricity, but does not affect the annual peak import of electricity. Flexible demand and batteries both enable increased self-consumption, but as batteries are more flexible, batteries were found to be the individual measure with the largest potential for increasing self-consumption.

The addition of a capacity payment generally incentivises the energy community to reduce peak loads by distributing EV charging, HP production and battery charging over longer periods. The results indicate, that for local grid areas with peak grid capacity limitations, capacity payments could be a tool for guiding the operation of energy communities. In grid areas without relevant peak capacity limitations, tax and tariff structures could instead be applied mainly to support and incentivise flexible operation and integration of RE through, e.g., dynamic tariffs or net-metering schemes.

In a 100% RE system, the flexible electricity consumption of the energy community was found to occur mainly during hours with excess VRE production. Different tax and tariff structures only to a limited extent change this. HPs in Avedøre Green City and the HPs in the surrounding national energy system have similar operational patterns, despite some underlying differences in principles for system operation. This indicates that the local HP operation of the analysed system is expected to function well within the national RE system. Across the modelled tax and tariff structures, EVs in Avedøre Green City are charged more intensively for shorter periods than what is the case in the included national RE scenario. For EVs it may be relevant to establish an economic framework that incentivises a reduction in peak charging, this could for example be in the form of capacity payments.

CRediT authorship contribution statement

Rasmus Magni Johannsen: Conceptualization, Methodology, Formal analysis, Data curation, Visualization, Writing – original draft, Writing – review & editing. **Peter Sorknæs:** Conceptualization, Methodology, Data curation, Writing – original draft, Writing – review & editing. **Karl Sperling:** Conceptualization, Writing – original draft, Writing – review & editing. **Poul Alberg Østergaard:** Conceptualization, 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.

Data availability

Data is available in the Appendix.

Acknowledgements

This project has received funding from the EU-Regional fund under grant agreement No RFD-16-0024.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enconman.2023.117112.

References

[1] Yazdanie M, Densing M, Wokaun A. The role of decentralized generation and storage technologies in future energy systems planning for a rural agglomeration in Switzerland. Energy Policy 2016;96:432–45. https://doi.org/10.1016/J.ENPOL.2016.06.010.
[2] Akorede MF, Hizam H, Pouresmaeil E. Distributed energy resources and benefits to the environment. Renew Sustain Energy Rev 2010;14:724–34. https://doi.org/10.1016/J.RSER.2009.10.025.
[3] Sperling K, Hvelplund F, Mathiesen BV. Centralisation and decentralisation in strategic municipal energy planning in Denmark. Energy Policy 2011;39:1338–51. https://doi.org/10.1016/j.enpol.2010.12.006.
[4] Krog L. How municipalities act under the new paradigm for energy planning. Sustain Cities Soc 2019;47:101511. https://doi.org/10.1016/j.scs.2019.101511.
[5] Johannsen RM, Østergaard PA, Maya-Drysdale D, Mouritsen LKE. Designing Tools for Energy System Scenario Making in Municipal Energy Planning. Energies 2021;14:1442. https://doi.org/10.3390/en14051442.
[6] Drysdale D, Vad Mathiesen B, Lund H. From Carbon Calculators to Energy System Analysis in Cities. Energies 2019;12:2307. https://doi.org/10.3390/en12122307.

[7] Petersen JP. Energy concepts for self-supplying communities based on local and renewable energy sources: A case study from northern Germany. Sustain Cities Soc 2016;26:1–8. https://doi.org/10.1016/j.scs.2016.04.014.

[8] Otamendi-Irizar I, Grijalba O, Arias A, Pennese C, Hernández R. How can local energy communities promote sustainable development in European cities? Energy Res. Soc Sci 2022:84. https://doi.org/10.1016/J.ERSS.2021.102363.

[9] European Commision. Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast) 2019. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32019L0944 (accessed January 31, 2023).

[10] European Commision. Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast) 2018. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0082.01.ENG (accessed January 31, 2023).

[11] Lowitzsch J, Hoicka CE, van Tulder FJ. Renewable energy communities under the 2019 European Clean Energy Package – Governance model for the energy clusters of the future? Renew Sustain Energy Rev 2020;122:109489. https://doi.org/10.1016/J.RSER.2019.109489.

[12] de São JD, Faria P, Vale Z. Smart energy community: A systematic review with metanalysis. Energy Strateg Rev 2021;36:100678. https://doi.org/10.1016/J.ESR.2021.100678.

[13] Gui EM, MacGill I. Typology of future clean energy communities: An exploratory structure, opportunities, and challenges. Energy Res Soc Sci 2018;35:94–107. https://doi.org/10.1016/J.ERSS.2017.10.019.

[14] Fleischhacker A, Lettner G, Schwabeneder D, Auer H. Portfolio optimization of energy communities to meet reductions in costs and emissions. Energy 2019;173: 1092–105. https://doi.org/10.1016/J.ENERGY.2019.02.104.

[15] Dal Cin E, Carraro G, Volpato G, Lazzaretto A, Danieli P. A multi-criteria approach to optimize the design-operation of Energy Communities considering economic-environmental objectives and demand side management. Energy Convers Manag 2022:263. https://doi.org/10.1016/J.ENCONMAN.2022.115677.

[16] Rodrigues L, Gillott M, Waldron J, Cameron L, Tubelo R, Shipman R, et al. User engagement in community energy schemes: A case study at the Trent Basin in Nottingham. UK Sustain Cities Soc 2020;61:102187. https://doi.org/10.1016/J.SCS.2020.102187.

[17] Hewitt RJ, Bradley N, Compagnucci AB, Barlagne C, Ceglarz A, Cremades R, et al. Social innovation in community energy in Europe: A review of the evidence. Front Energy Res 2019;7:31. https://doi.org/10.3389/FENRG.2019.00031/BIBTEX.

[18] Thellufsen JZ, Lund H, Sorknæs P, Østergaard PA, Chang M, Drysdale D, et al. Smart energy cities in a 100% renewable energy context. Renew Sustain Energy Rev 2020;129:109922. https://doi.org/10.1016/j.rser.2020.109922.

[19] Lund H, Østergaard PA, Connolly D, Mathiesen BV. Smart energy and smart energy systems. Energy 2017;137:556–65. https://doi.org/10.1016/j.energy.2017.05.123.

[20] Backe S, Zwickl-Bernhard S, Schwabeneder D, Auer H, Korpås M, Tomasgard A. Impact of energy communities on the European electricity and heating system decarbonization pathway: Comparing local and global flexibility responses. Appl Energy 2022:323. https://doi.org/10.1016/J.APENERGY.2022.119470.

[21] Stroink A, Diestelmeier L, Hurink JL, Wawer T. Benefits of cross-border citizen energy communities at distribution system level. Energy Strateg Rev 2022;40: 100821. https://doi.org/10.1016/J.ESR.2022.100821.

[22] Gorroño-Albizu L. The Benefits of Local Cross-Sector Consumer Ownership Models for the Transition to a Renewable Smart Energy System in Denmark. An Exploratory Study Energies 2020:13. https://doi.org/10.3390/en13061508.

[23] Petrucci A, Barone G, Buonomano A, Athienitis A. Modelling of a multi-stage energy management control routine for energy demand forecasting, flexibility, and optimization of smart communities using a Recurrent Neural Network. Energy Convers Manag 2022:268. https://doi.org/10.1016/J.ENCONMAN.2022.115995.

[24] Kachirayil F, Weinand JM, Scheller F, McKenna R. Reviewing local and integrated energy system models: insights into flexibility and robustness challenges. Appl Energy 2022;324:119666. https://doi.org/10.1016/J.APENERGY.2022.119666.

[25] Panos E, Kober T, Wokaun A. Long term evaluation of electric storage technologies vs alternative flexibility options for the Swiss energy system. Appl Energy 2019; 252:113470. https://doi.org/10.1016/J.APENERGY.2019.113470.

[26] Tostado-Véliz M, Kamel S, Hasanien HM, Turky RA, Jurado F. Optimal energy management of cooperative energy communities considering flexible demand, storage and vehicle-to-grid under uncertainties. Sustain Cities Soc 2022:84. https://doi.org/10.1016/J.SCS.2022.104019.

[27] Cossutta M, Pholboon S, McKechnie J, Sumner M. Techno-economic and environmental analysis of community energy management for peak shaving. Energy Convers Manag 2022:251. https://doi.org/10.1016/J.ENCONMAN.2021.114900.

[28] Danish Energy Agency. Annual and monthly statistics 2019. https://ens.dk/en/our-services/statistics-data-key-figures-and-energy-maps/annual-and-monthly-statistics (accessed November 12, 2019).

[29] Grundahl L, Nielsen S. Heat atlas accuracy compared to metered data. Int J Sustain Energy Plan Manag 2019:23. https://doi.org/10.5278/ijsepm.3174.

[30] Mathiesen BV, Lund H, Nielsen S, Sorknæs P, Thellufsen JZ, Moreno D. Heat Plan Denmark 2021 - A Climate Neutral Heat Supply — Aalborg University's Research Portal 2021. https://vbn.aau.dk/en/projects/varmeplan-danmark-2021-en-klimaneutral-varmeforsyning (accessed January 5, 2023).

[31] Sorknæs P, Johannsen RM, Sperling K. Energy communities in different tax- and tariff structures: An analysis of Avedøre Green City — Aalborg University's Research Portal 2022. https://vbn.aau.dk/en/publications/energifællesskaber-i-forskellige-afgifts-og-tarifstrukturer-en-an (accessed January 3, 2023).

[32] Danish Ministry of Climate Energy and Utilities. Electricity supply act. LBK Nr 984 Af 12/05/2021 2021. https://www.retsinformation.dk/eli/lta/2021/984.

[33] European Commision. Regulation (EU) 2019/943 of the European Parliament and of the Council on the internal market for electricity (recast) 2019. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019R0943 (accessed January 17, 2023).

[34] Østergaard PA, Andersen AN, Sorknæs P. The business-economic energy system modelling tool energyPRO. Energy 2022;257:124792. https://doi.org/10.1016/J.ENERGY.2022.124792.

[35] Andersen AN, Østergaard PA. A method for assessing support schemes promoting flexibility at district energy plants. Appl Energy 2018;225:448–59. https://doi.org/10.1016/j.apenergy.2018.05.053.

[36] Andersen AN, Østergaard PA. Support schemes adapting district energy combined heat and power for the role as a flexibility provider in renewable energy systems. Energy 2020;192:116639. https://doi.org/10.1016/J.ENERGY.2019.116639.

[37] Østergaard PA, Andersen AN. Variable taxes promoting district heating heat pump flexibility. Energy 2021;221:119839. https://doi.org/10.1016/j.energy.2021.119839.

[38] Johannsen RM, Arberg E, Sorknæs P. Incentivising flexible power-to-heat operation in district heating by redesigning electricity grid tariffs. Smart Energy 2021;2: 100013. https://doi.org/10.1016/J.SEGY.2021.100013.

[39] Sneum DM, Sandberg E, Koduvere H, Olsen OJ, Blumberga D. Policy incentives for flexible district heating in the Baltic countries. Util Policy 2018;51:61–72. https://doi.org/10.1016/j.jup.2018.02.001.

[40] Trømborg E, Havskjold M, Bolkesjø TF, Kirkerud JG, Tveten ÅG. Flexible use of electricity in heat-only district heating plants. Int J Sustain Energy Plan Manag 2017;12:29–46. https://doi.org/10.5278/ijsepm.2017.12.4.

[41] Andersen AN, Østergaard PA. Analytic versus solver-based calculated daily operations of district energy plants. Energy 2019;175:333–44. https://doi.org/10.1016/J.ENERGY.2019.03.096.

[42] Lund H, Mathiesen BV, Thellufsen JZ, Sorknæs P, Chang M, Kany MS, et al. IDA Climate Response 2045 Summary 2021. https://vbn.aau.dk/da/publications/aa69d04b-5006-4946-8006-4f35ef622805 (accessed January 19, 2023).

[43] Lund H, Thellufsen JZ, Sorknæs P, Mathiesen BV, Chang M, Madsen PT, et al. Smart energy Denmark. A consistent and detailed strategy for a fully decarbonized society. Renew Sustain Energy Rev 2022;168. https://doi.org/10.1016/j.rser.2022.112777.

[44] Lund H, Skov IR, Thellufsen JZ, Sorknæs P, Korberg AD, Chang M, et al. The role of sustainable bioenergy in a fully decarbonised society. Renew Energy 2022;196: 195–203. https://doi.org/10.1016/j.renene.2022.06.026.

[45] Lund H, Thellufsen JZ, Østergaard PA, Sorknæs P, Skov IR, Mathiesen BV. EnergyPLAN – Advanced analysis of smart energy systems. Smart Energy 2021;1: 100007. https://doi.org/10.1016/j.segy.2021.100007.

[46] Bergaentzlé C, Jensen IG, Skytte K, Olsen OJ. Electricity grid tariffs as a tool for flexible energy systems: A Danish case study. Energy Policy 2019;126:12–21. https://doi.org/10.1016/j.enpol.2018.11.021.

[47] Van Der Schoor T, Scholtens B. Power to the people: Local community initiatives and the transition to sustainable energy. Renew Sustain Energy Rev 2015;43: 666–75. https://doi.org/10.1016/J.RSER.2014.10.089.

[48] Terlouw T, AlSkaif T, Bauer C, van Sark W. Multi-objective optimization of energy arbitrage in community energy storage systems using different battery technologies. Appl Energy 2019;239:356–72. https://doi.org/10.1016/J.APENERGY.2019.01.227.

[49] Zhang L, Yang Y, Li Q, Gao W, Qian F, Song L. Economic optimization of microgrids based on peak shaving and CO2 reduction effect: A case study in Japan. J Clean Prod 2021;321:128973. https://doi.org/10.1016/J.JCLEPRO.2021.128973.

[50] Lund H, Kempton W. Integration of renewable energy into the transport and electricity sectors through V2G. Energy Policy 2008;36:3578–87. https://doi.org/10.1016/J.ENPOL.2008.06.007.