Centralized vs. distributed energy storage – Benefits for residential users

Zakeri, Behnam; Gissey, Giorgio Castagneto; Dodds, Paul E.; Subkhankulova, Dina

Published in:
Energy

DOI (link to publication from Publisher):
10.1016/j.energy.2021.121443

Publication date:
2021

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

Energy 236 (2021) 121443

Contents lists available at ScienceDirect

Energy

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

Centralized vs. distributed energy storage – Benefits for residential users

Behnam Zakeri [a, b, c, d, *, 1], Giorgio Castagneto Gissey [b, 1], Paul E. Dodds [b], Dina Subkhankulova [b]

[a] Energy, Climate, and Environment Program, International Institute for Applied Systems Analysis (IIASA), Austria
[b] UCL Energy Institute, University College London, UK
[c] Energy Efficiency and Systems, Aalto University, Espoo, Finland
[d] Sustainable Energy Planning, Aalborg University, Copenhagen, Denmark

ARTICLE INFO

Article history:
Received 31 December 2020
Received in revised form
4 July 2021
Accepted 6 July 2021
Available online 10 July 2021

Keywords:
Electrical energy storage
Energy policy
Energy system model
Decentralized energy
Value of energy storage
Smart energy systems

ABSTRACT

Distributed energy storage is a solution for increasing self-consumption of variable renewable energy such as solar and wind energy at the end user site. Small-scale energy storage systems can be centrally coordinated by "aggregation" to offer different services to the grid, such as operational flexibility and peak shaving. This paper shows how centralized coordination vs. distributed operation of residential electricity storage (home batteries) could affect the savings of owners. A hybrid method is applied to model the operation of solar photovoltaic (PV) and battery energy storage for a typical UK householder, linked with a whole-system power system model to account for long-term energy transitions. Based on results, electricity consumers can accumulate greater savings under centralized coordination by between 4 and 8% when operating no technology, by 3-11% with electricity storage alone, by 2-5% with stand-alone solar PV, while 0-2% with PV-battery combined. Centralized coordination of home batteries offers more optimized electricity prices in the system, and as such, higher private savings to all consumers. However, consumers without onsite energy technologies benefit more than PV-battery owners. Therefore, based on system-level benefits of aggregation, the regulator should incentivize prosumers with PV-battery, who are able to balance their electricity supply-demand even without central coordination, to let their storage be controlled centrally. Possible revenues of storage owners from ancillary services as well as the cost of aggregation (e.g., transaction fees charged by aggregators) are not considered in this analysis.

1. Introduction

1.1. Distributed solar PV and energy storage

Many governments worldwide plan to increase the share of renewable energy for environmental, economic, and energy security reasons. For achieving renewable energy targets, different incentives and support schemes have been put in place to promote the deployment of renewable energy through decentralized and distributed generation, e.g., through solar photovoltaic (PV) at consumer sites.

Electricity generation from solar PV is not always correlated with electricity demand. For example, in cold climate countries electricity demand peaks typically happen in the evenings when there is no solar energy [1]. There are different solutions for increasing the consumption of solar PV onsite, or so called “self-consumption”, which can maximize the benefits of distributed energy generation and minimize the electricity bills of the PV owner [2]. One of the common solutions is to export extra electricity from solar PV to the grid. However, in large-scale penetration of distributed solar PV, the export of electricity from many buildings to the distribution grid at peak generation times will cause contingencies and grid imbalances [3], resulting in additional costs for the system [4]. Moreover, the value of self-consumption of solar electricity for the private owner is typically much higher compared to the gains from exporting electricity to the grid, as export tariffs are typically lower than purchasing electricity prices [5]. Therefore,

* Corresponding author. IIASA, Schlossplatz 1, Laxenburg, Austria.
E-mail address: zakeri@iiasa.ac.at (B. Zakeri).
1 Authors with equal contribution.

https://doi.org/10.1016/j.energy.2021.121443

the private owner of solar PV prefers to find different ways to increase their self-consumption, e.g., by storing electricity via electrical energy storage[2] (EES) systems such as batteries [6].

EES can balance the mismatch between onsite solar PV generation and electricity demand by storing electric energy at hours of low demand in daytime and discharging that to meet evening peaks. Different studies have shown that pairing solar PV with batteries (PV-EES) increases self-consumption of solar energy onsite [7] and can offer significant cost savings to the private owner. For example, Zhang et al. [8] shows that paring solar PV with a home battery in California and Hawaii is a feasible investment with a payback period of less than 10 years for different building types, while others demonstrate possible cost savings for PV-battery owners in high latitude countries in Europe under different energy storage policies [9]. Also, from the system operator's perspective, distributed EES devices can contribute toward balancing the (distribution) grid by reducing peak contingencies [10] and grid management costs [11]. This can offer the Transmission and Distribution (T&D) grid operator significant cost savings for postponing T&D investments and grid fortification measures at the low-voltage level [12,13].

However, the cost of batteries are still at the start of their learning curves [14], which diminishes the financial viability of investment in such technologies, from a private owner's perspective [2]. Different studies show that a PV-EES system is not economically viable under current market conditions in different countries without additional financial supports [15]or policy incentives [16,17]. These policies are, for example, capital subsidies [8], enhanced time-of-use tariffs [18,19], peer to peer trading [20], or provision of *revenue stacking*[3] [21]. Revenue stacking is considered as one of the most effective support mechanisms for enhancing economic profitability of EES systems [22], which can be possible by combining the onsite use of EES with offering grid services, such as balancing the load and/or ancillary services as shown in Refs. [23,24].

1.2. Coordination of distributed solar PV-storage systems

Providing grid services in many power systems is regulated by the System Operator with some technical requirements for candidate technologies. These requirements are commonly specified as response time, availability, reliability, minimum capacity rating, etc. For example, the requirement for an energy technology for providing balancing services in Finland is a minimum power output of 5 MW [25]. These requirements leave many distributed technologies such as PV-EES systems with a typical size of a few Kilowatts unqualified for entering such marketplaces. To overcome such barriers of entry, the available capacity of many small-scale distributed technologies can be aggregated and coordinated by aggregators, which are typically third-party companies benefiting from control and transaction fees. Therefore, the owner of a PV-EES system can operate their asset either independently mainly for managing their own generation and demand or, alternatively, they could offer their available storage capacity to be coordinated with other small-scale EES units to participate in wholesale electricity markets through aggregators.

Aggregators can offer the combined capacity of EES technologies in wholesale electricity markets, to meet the needs of the System Operator for load management and ancillary services, e.g., for Fast Frequency Response (FFR) [26]. Different studies have shown that the aggregation of small-scale EES systems could reduce the risk of higher electricity prices at peak times [27], improve social welfare [28], and increase the integration of renewable energy in the grid [29], compared to uncoordinated, independent management of such assests by their owners. As consumers are unlikely to be able to provide such services and exploit arbitrage benefits simultaneously, they may operate their resources in a way that minimizes their own electricity bills, irrespective of the potential system-level benefits they could offer through aggregation [27]. Fig. 1 illustrates the main features of these two schemes for the operation of distributed energy storage, i.e., the uncoordinated operation of EES by multiple owners for their private benefits (a), versus a centrally coordinated operation of small EES systems through an aggregator.

1.3. Private and system-level value of solar PV and energy storage

The private value of solar PV and EES to consumers is the financial gain that a consumer can obtain by reducing its electricity bills [30]. Wholesale electricity prices vary widely on an hourly or half-hourly basis and are typically the largest component of electricity costs of consumers, comprising nearly 40–60% of their electricity bills in Europe [20]. Most *prosumers*[4] have been early adopters, environmental enthusiasts, looking for energy security by being independent from the grid, and/or motivated by social and peer effects; not necessarily motivated purely by cost-benefit analysis [31,32]. Yet the savings that prosumers with EES could achieve is a key indicator to show if more widespread adoption of such distributed energy technologies is likely to occur in the future or not.

Numerous studies have investigated the profitability of consumer investments in solar PV and EES. Many studies have derived the cost of electricity and assessed the profitability of investments by considering metrics such as the Net Present Value (NPV), Internal Rate of Return (IRR), or the Return on Investment (ROI) of the investment. Other work adopts the “grid parity” concept to evaluate the profitability of storage by considering the levelized cost of electricity [33]. These studies, however, do not take a whole electricity system approach for modelling the future electricity prices, on which the economic profitability of PV-storage systems depends. A recent study considers the impacts of a changing electricity system on the consumer savings, but does not account for potential impacts of the development of demand-side technologies on the system [2]. This paper extends the previous work by accounting for the impact of the EES on the system, which, if neglected, may overestimate the potential benefits of the EES for the owner. Because the larger the capacity of EES in the system offered by many private owners, the lower the value of arbitrage for each EES owner as the price gap between peak and off-peak will diminish.

The value of solar PV-EES to consumers is different from the value they may offer to the wider electricity system. Solar PV-EES and other distributed energy technologies could provide the electricity system with different services, while offering energy security and cost savings to the owner. However, maximizing the private value of distributed technology may not simultaneously offer the highest system-wide value. Energy security has a private value to the consumer, whereas the flexibility it offers to the system has a

[2] The terms EES, “electricity storage”, “energy storage”, and “storage” are interchangeably used in this paper for referring to technologies that can store electricity and discharge it back at a reasonable response time. Examples of such technologies include secondary electro-chemical batteries, flow batteries, pumped hydropower storage (PHS), etc.

[3] Revenue stacking or aggregation of benefits means using an EES device for offering multiple services, such as energy arbitrage, balancing services, and T&D support; and receiving revenues for each service.

[4] Prosumers are defined as consumers with the ability to produce electricity from solar PV.

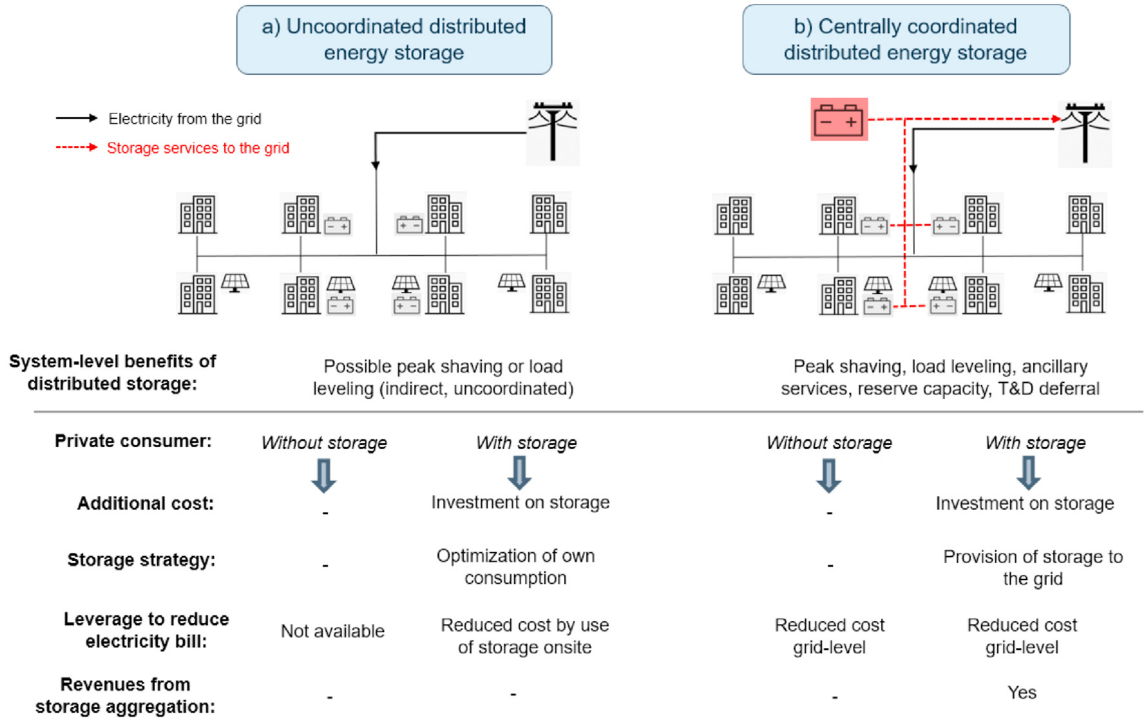

Fig. 1. Schematic representation of uncoordinated (a) and centrally coordinated (b) operation of distributed electricity storage devices. The main characteristics of each mode of operation, including benefits for the system and the private owner is depicted under each scheme.

social value. The social (system) value of these resources will depend on whether these resources are being operated to reduce electricity system costs, a benefit for all consumers, or to minimize private electricity costs. Solar PV may reduce electricity demand if it is subject to individual coordination by cost minimizing consumers, which would reduce prices for all consumers in the system [27]. Privately coordinated EES could increase electricity prices as there is potential that most of EES owners charge simultaneously at low price hours resulting in significant increase of electricity demand and prices in those hours, affecting all electricity consumers. But private EES devices could also reduce peak demand, hence prices, if they were optimally operated in coordination, lowering electricity prices for all consumers [34].

Several studies focusing on EES in different countries have concluded that centralized coordination of distributed energy resources could offer numerous system-level advantages. For example, central coordination of EES can offer required flexibility in matching load and supply, reducing the cost of procuring flexible capacity for the system [35,36]. The value of aggregation to an electricity system has been shown to increase as more consumers are aggregated [37], with small contributions by each customer leading to large reductions in electricity costs for all consumers [38]. It is also argued that distributed energy devices could improve social welfare under efficient aggregation and coordinated operation of technologies [28]. Castagneto Gissey et al. [27] investigated the impact of centralized and distributed scheduling of EES on electricity prices, highlighting that a centralized coordination offers 7% lower mean electricity price and 60% lower price volatility in the system. Sousa et al. [39] compares a peer-to-peer (P2P) versus a community market for energy trade, concluding that P2P trade offers the highest social welfare. It is further shown that the aggregator can control the capacity of distributed EES to manage the frequency deviations in the grid in a more effective way [40]; another system-level benefit for all consumers. In a recent study [41], a whole-system comparison of centralized versus decentralized electricity planning is carried out, showing that coordinated planning can save between 7% and 37% of the total system costs. Last but not the least, Ahmadi et al. [42] applies a two-stage optimal coordination of central and local EES for showing the impact on system cost reduction and voltage profile enhancement.

However, none of the reviewed studies investigate the impact of the aggregation of distributed energy technologies (here PV-EES) on the private value of such technologies, i.e., the additional cost or benefit that the owner bears for letting the aggregator coordinate their PV-EES. This is an important question as the deployment of EES by consumers might be affected by the way the technology is operated throughout the system. Answering this question could reduce the uncertainty consumers face when investing in battery storage, thereby facilitating further deployment of storage resources when needed. This would help the electricity system to reduce costs and improve security of supply by making such resources available to provide multiple other system services. In this respect, it is crucial to understand how the deployment of EES resources by consumers could be affected as more EES is aggregated throughout the electricity system. Our study investigates this too.

1.4. Objectives of this study

As mentioned earlier, pairing solar PV with EES can maximize the self-consumption of PV electricity for consumers who adopt the technology and minimize their electricity costs. Yet it remains unclear how the savings that these consumers can expect from their storage device might be affected by the way of coordination of EES in the electricity system. This paper investigates how aggregator-led and consumer-led operation of EES capacity might affect the private economic value of solar PV and EES for a UK electricity consumer with typical domestic electricity consumption. Different future developments of the energy system are explored to analyse the economic savings a consumer can achieve from investing in PV and batteries. Finally, it is shown that how these savings will be affected when more EES capacity is integrated into the electricity system through aggregation. By identifying these three gaps in the literature, this paper aims to answer the following research questions:

1. How would aggregator-led and consumer-led operations of EES in the electricity system affect savings to a typical consumer who pairs solar PV with storage?
2. Which system evolutions or energy pathways are likely to explain the process by which EES aggregation could affect savings to a consumer pairing solar PV with storage?
3. What is the relationship between savings from pairing solar PV with storage to a private electricity consumer and the level of electricity system-wide storage aggregation? In other words, how would additional aggregation of EES affect the savings to a typical consumer pairing solar PV with storage?

The remainder of this paper is structured as follows. Section 2 provides the methodology and describes the data used in this study. Section 3 reports our main results, which are discussed in Section 4. Conclusions are drawn in Section 5.

2. Methods

Onsite, small-scale batteries and electric vehicle-to-grid storage are some examples of distributed EES technologies for private consumers. The ever-growing electrification of transport, heating and other sectors are expected to change the pattern and magnitude of electricity demand over the coming decades [43]. Accurate modelling of electricity demand over such extended periods, i.e., 20–30 years, is crucial to understand how consumer electricity prices will vary in the future and how investment in distributed technologies will return economically. Also, transitions in the electricity supply side will affect wholesale electricity prices. Higher shares of wind and nuclear capacity in the power system will offer different electricity prices and price volatility compared to a thermal power system relying on coal and gas. Hence, assessing the financial feasibility of investment in distributed energy technologies with 20–30 years of lifetime needs to be informed by a quantitative model of the overarching energy system for representing the increase in the use of non-conventional energy resources and possible transitions in the energy system.

2.1. A multi-level modelling framework

The modelling approach is based on soft-linking a national-level, electricity system management model (ESMA) to a consumer cost optimization model. The input data of ESMA, i.e., electricity demand, power capacity mix, and fuel prices are based on the UK "future energy scenarios" developed by the national energy regulatory, National Grid [44]. The electricity system model ESMA is designed for evaluating the operation and dispatch of a given power system mix for a time-period of one year (8760 h). It is ideally suited to generate wholesale prices under different scenarios for EES and the rest of the system. Wholesale electricity prices are then converted into retail electricity tariffs based on different tariff designs, i.e., time of use (ToU), static, and dynamic tariffs. These tariffs are fed into an electricity private cost minimization model that optimizes the use of solar PV and EES for a consumer with a typical electricity consumption profile. This framework accounts for possible future evolutions of the energy system considering how EES deployments are likely to affect savings of consumers. The electricity generation costs, e.g., future capital cost of different power plants, are based on the output of the UKTM energy system model [45].

The modelling framework including the linkage between different models and modules to derive consumer savings is illustrated in Fig. 2. This framework has been previously applied to calculate solar PV-battery consumer investments [2] and value of storage aggregation to the system and electricity prices [27]. This is extended in this study by iterating electricity demand of prosumers, which itself is based on the optimal scheduling of PV-EES according to retail prices, back to the electricity dispatch model. With the updated electricity demand, the electricity dispatch model generates a new set of hourly electricity prices, which will affect the retail price for all consumers, both with and without onsite energy technologies. This process, highlighted in red in Fig. 2, continues until electricity prices converge in two consecutive iterations.

The ESMA model has been validated on an hourly basis against both the historical data and future energy scenario developed by National Grid. The results of validation suggest that the hourly demand curve modelled by ESMA stays within an acceptable level of agreement with historical data, e.g., with an average correlations coefficient of 0.92 for 8760 hourly demand data points for the reference year 2015. Similarly, the analysis of hourly electricity prices simulated by ESMA in different season shows a high degree of agreement with historical spot prices, with an average correlation of 0.83 in winter, while 0.91–0.93 correlation on other seasons. The comparison of the ESMA's future scenarios with those modelled by National Grid shows a very high degree of agreement, yet some slight differences exist due to different modelling assumptions and limitations of ESMA. A detailed analysis on validation of the model is represented in Chapter 5 in Ref. [46].

The applied modelling work has some limitations and shortcomings. Assuming fixed, average fuel prices throughout each year, i.e., fixed gas or biomass prices, may not conform with reality where fuel prices change by season. ESMA does not include electricity consumers under the Economy 7 tariff who benefit from a lower night tariff, which may result in a slight demand and price difference in winter. ESMA represents each technology as a large power plant which is different from the strategy that each single power plant may adopt.

The model is run over a 26-year period, 2015–2040, initially with the objective to optimize the consumer's utility based on the lifetimes of distributed PV-EES systems. ESMA minimizes electricity costs and calculates wholesale electricity prices under the assumption of centralized and distributed coordination of demand-side EES technologies. Additional information on the modelling framework and formulation is provided in the Supporting Information (Appendix A-C). Appendix H summarizes main data sources and assumptions of the model.

Retail electricity prices are calculated by adding a time-dependent mark-up over the wholesale prices, which is assumed to account for the electricity network management and distribution fees [47] (see Appendix F for calculation of prices). Static and dynamic ToU electricity tariffs are calculated based on retail prices, calibrated to historical tariff data (assuming same ratios between tariffs and retail prices as today for future years).

2.2. Future energy scenarios

The evolution of the energy system over time will impact wholesale electricity prices, and hence, consumer retail prices. A whole systems approach is adopted to account for these future transitions systematically and consistent with the National Grid scenarios, which are based on a broad stakeholder engagement and modelling. Four possible evolutions of the energy system are

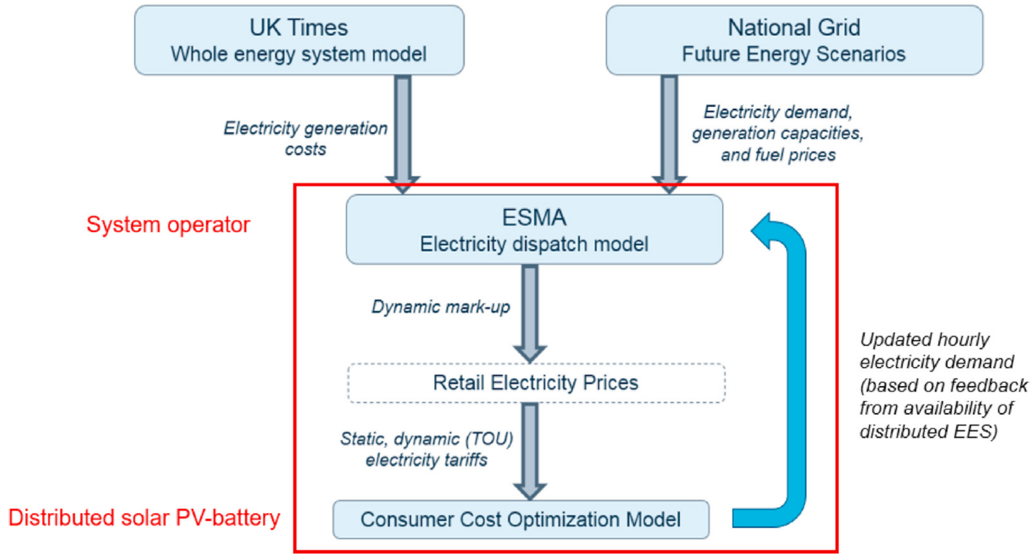

Fig. 2. Relationship between different models used in this analysis.

considered according to National Grid's Future Energy Scenarios [44]. These scenarios are chosen as the basis of our analysis as they cover a wide range of future energy pathways represented across two axes for green ambition and prosperity. The GB Office of Gas and Electricity Markets (Ofgem), the National Regulatory Authority, has reviewed these scenarios, which gives them more merit for our analysis.

These four energy transition pathways include: (i) Gone Green, which is the most ambitious renewable expansion scenario, where the UK meets its renewable targets; (ii) Consumer Power, a consumer-centred scenario with energy security and costs as main drivers of decisions; (iii) Slow Progression, a scenario with low ambitions for decarbonization; and (iv) No Progression, where the status quo persists and there is a negligible deployment of renewables and EES. Gone Green has the highest ambition on renewables and storage capacity, while No Progression is similar to the present-day energy system and has the lowest capacity of renewables from all four scenarios. Table A3 in Supplementary Material shows the key developments of the power sector in 2030 under these future scenarios. Fig. 3 portrays the installed power capacities for each of the future energy scenarios. More details of the share of each generation mode are provided in Appendix H, Table A4.

2.3. Consumer electricity cost optimization

Two cases of EES scheduling are examined, in which consumers respond to either distributed or centralized coordination. Under the former, demand-side storage resources are autonomously optimized by consumers. In a centralized scheduling system, an aggregator coordinates electricity dispatch from EES by iterative negotiation with consumers, whose resources it does not know, enabling them to participate in the wholesale market. Centralized coordination mimics the current arrangements for large-scale EES technologies in the UK and major worldwide liberalized markets, such as for PHS. Transaction costs relating to aggregation are neglected for simplicity. Distributed coordination reflects the behaviour of consumers who individually schedule their flexible resources to smoothen their own demand profiles and minimize their own electricity bills. More information on our coordination algorithms is provided in Appendix E.

The financial viability of different combinations of investments in solar PV and EES for a typical UK domestic electricity user[5] are examined under different energy scenarios. The household's electricity bill is dependent on the consumer's load profile, and on the electricity generated from solar PV, which exhibit intra-day, monthly and seasonal variations.

End users with onsite generation from PV are entitled for feed-in tariffs (FiTs) of £0.049 kWh^{-1} for electricity generation [47] and an export-to-grid tariff of £0.043 kWh^{-1}. FiT payments are assumed to cease after 20 years and to increase with the retail price index (RPI) of 3.4% p.a [48]. An average retail electricity tariff is considered based on UK National Statistics: a static tariff of £0.15 kWh^{-1} and dynamic ToU tariff including on-peak £0.16 kWh^{-1} during the day (7:00–23:59) and off-peak tariff of £0.07 kWh^{-1} at nights (0:00–6:59) [48]. Future developments of static tariffs are estimated based on the average of wholesale electricity price in each season. We use the static tariff as the basis to derive future values for day and night ToU tariffs (see Appendix H for more details).

The objective of a residential PV, EES, or PV-EES owner is to minimize the private costs of electricity bills. Under ToU tariffs, the lower rate during the off-peak period is suitable for charging the storage system. When the consumer operates PV, a 4-kW PV system is considered; and for EES, a 6.4 kWh–3.3 kW battery, with a lifetime of 13 years or 5000 cycles (Li-ion batteries) [49]. The battery capacity degradation and efficiency losses are taken into account as described in Appendix B. A discount rate of 5% p.a. is assumed, based on the recommendations of the UK Committee on Climate Change. Appendix G reports the details on the consumer PV-EES optimization model and the data used for modelling PV-EES technologies.

The electricity costs are calculated for four consumer technology combinations: (i) no technology; (ii) an EES system (EES-only); (iii) a solar PV system (PV-only); and (iv) both a solar PV and an EES system (PV-EES). We show the value of EES, which is derived by comparing annual electricity costs in the PV-EES scenario relative to the PV-only scenario. The base case scenario for deriving the relative savings of other scenarios is the no-technology case with

[5] This user is represented by a three-bedroom dwelling with a load profile displaying mean percentage night consumption of 30% and 55% under static and Economy7 ToU tariffs, respectively [47].

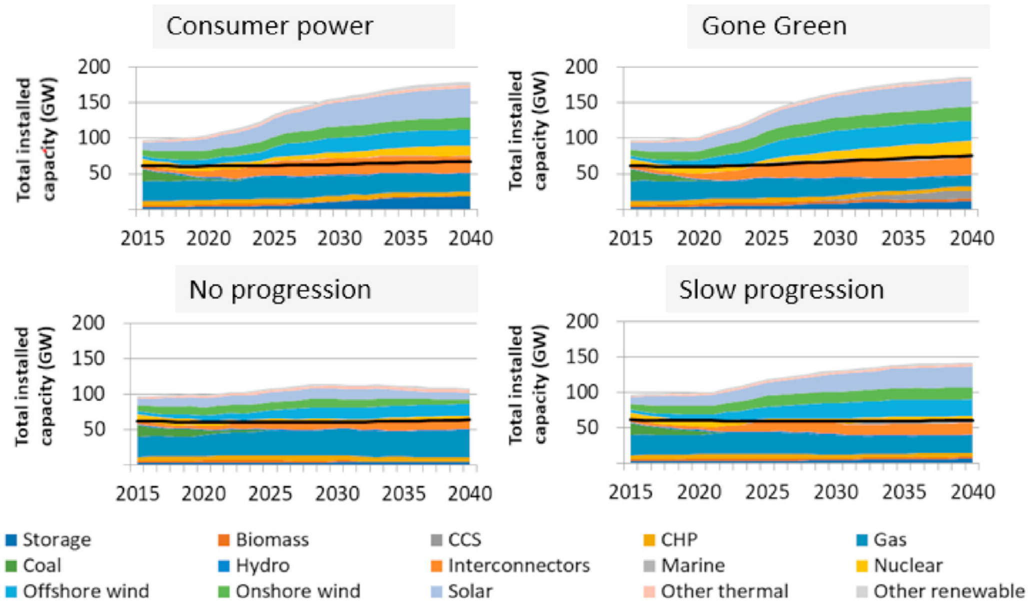

Fig. 3. Electricity generation mix in each future energy scenario [44].

static electricity tariffs.

3. Results

Two types of energy storage coordination, i.e., coordinated and distributed, are considered for calculations. The results are based on the data of annual electricity costs and savings, averaged over the modelling period of 2015–2040. The results are reported relative to a base case scenario, i.e., the No Progression scenario under static tariff and with no onsite energy technology investments.

The results show that the evolution of the energy system and the scheduling coordination regime have meaningful impacts on annual savings by the consumer. Distributed coordination generally induces 4–11% lower savings than centralized coordination, whereas the system's evolution accounts for changes in savings by 1–27%. The largest savings occur in scenarios with high storage and renewable capacity. The impact of additional storage capacity in the electricity system on the savings to the consumer when aggregated to participate in the wholesale market is explored too.

3.1. Private savings under centralized and distributed coordination

The results of the centralized coordination is presented in Table 1. The annual electricity bills and potential savings in the electricity bill are compared for consumers whose EES capacity in the electricity system is coordinated by an aggregator and scheduled centrally. The results are illustrated for four different technology options under static and ToU tariffs and for each future energy scenario.

The results show that the consumer savings is dependent on the future energy scenarios for the entire energy system. Consumer Power scenario, in which future policies are consumer-centred and promoting distributed generation offers the highest savings for all technology combinations. Gone Green and Consumer Power scenarios offer 18% and 22% annual savings, respectively, even in the case when the consumer has no investment in distributed technologies, i.e., “No technology”. This is due to higher renewable energy in these scenarios, larger share of electricity storage, and lower electricity prices compared to No Progression.

Fig. 4 compares the average annual savings in the electricity bill in the centralized coordination for two different types of tariffs. The results show that PV-battery offers the highest savings for consumers ranging between 81 and 86% depending on the future scenario.

However, battery alone offers no higher benefits compared to the no-technology case, as under the static tariff there will be no potential for price arbitrage by EES, as electricity prices are constant for the consumer. The annual savings of the consumer from

Table 1
Annual electricity bills and possible savings (£ p.a.) for a typical consumer under centralized coordination.

Centralized coordination		No Progression		Slow Progression		Consumer Power		Gone Green	
Tariff	Technology	Bill (£ p.a.)	Savings[a] (£ p.a.)	Bill (£ p.a.)	Savings (£ p.a.)	Bill (£ p.a.)	Savings (£ p.a.)	Bill (£ p.a.)	Savings (£ p.a.)
Static	No technology	574	–	541	33	449	125	470	104
	EES	574	0	541	33	449	125	470	104
	PV	363	211	342	232	284	290	297	277
	PV-EES	107	467	98	476	78	496	82	492
ToU	No technology	540	34	515	59	420	154	449	125
	EES	405	169	389	185	321	253	339	235
	PV	307	267	298	276	244	330	260	314
	PV-EES	92	482	87	487	68	506	73	501

[a] The savings are shown as difference relative to the base scenario, i.e., consumers having “No technology” onsite, static tariffs, and under the business-as-usual scenario (No Progression).

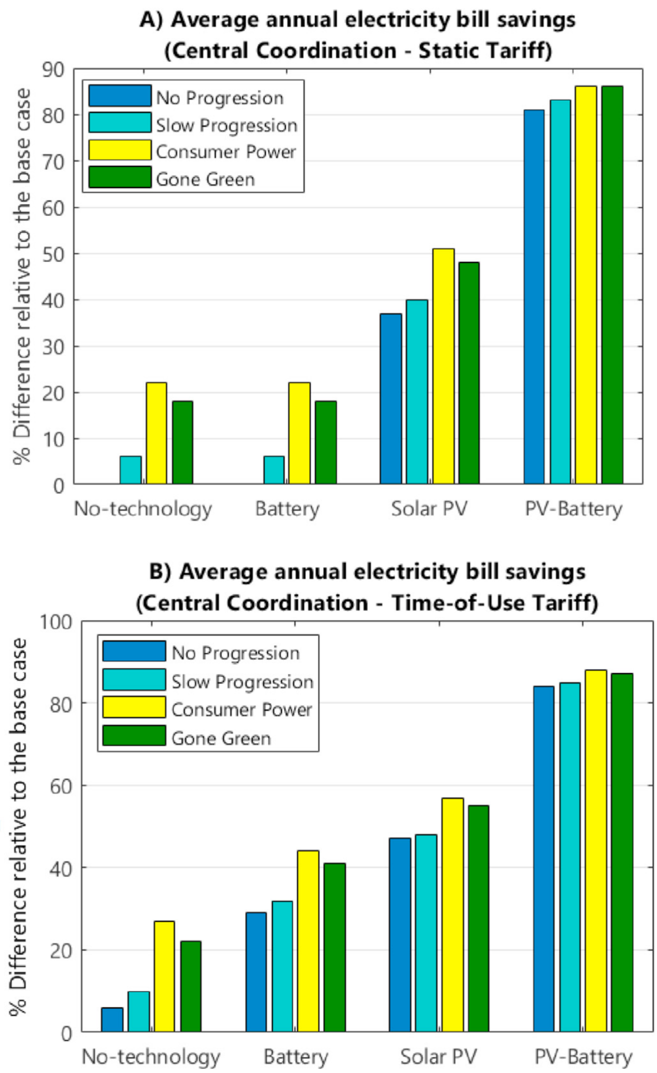

Fig. 4. Annual electricity bill savings for a typical consumer with different distributed energy technology options in centralized coordination, under (A) a static and (B) Time-of-use (ToU) tariff, and for different future energy scenarios. The values are the average of 2016–2040 and show % change in savings relative to the base case, which is "No-technology" under a static tariff, and No Progression Scenario with the annual cost of 574£.

investing in solar PV alone (without EES) varies between 37% and 51% of the base case costs, with the lower range for No Progression scenario and the highest savings for Consumer Power.

The results for the battery-alone case show significant higher savings under a ToU tariff. When the consumer electricity prices differ between off-peak and peak hours, battery can offer electricity cost savings between 29 and 41%, depending on the future energy scenario. Moreover, investing on solar PV under the ToU tariff improves the annual cost savings by 6–10%-point compared to the static tariff (~56£ per year). A PV-battery system offers the highest savings under ToU as well, with a slight improvement compared to the static tariff (i.e., 1-3%-point). Also, the results show that the benefits of the PV-battery options are the least sensitive technology investment to future energy scenarios, offering savings ranging between 84% and 88% for the four energy scenarios. Table 2 summarizes the results of centralized coordination for different tariffs, technology choices, and the future scenarios.

Under centralized scheduling of the consumer's energy technologies in the electricity system, the typical electricity consumer gains substantially larger annual savings compared with the decentralized scheduling. This is valid for all combinations of technologies, tariffs and future energy scenarios. The consumer is able to accumulate greater savings in the centralized case by between 4 and 8% when operating no technology, by 3–11% with EES alone, by 2–5% with PV alone, and by 0–2% with both PV and EES. More notably, the higher savings in the centralized coordination compared to the distributed scheme decline as the consumer operates more onsite technologies. Operating more technologies implies greater electricity self-sufficiency, hence, a lower exposure to the risk of changes in retail electricity prices, which itself is affected by the type of scheduling coordination of EES by other consumers in the system (see Fig. 5).

Consumers with "No technology" make higher electricity bill savings in the centralized coordination scheme due to the system operator being able to improve the balancing of load and flexibility resources, which results in lower peak electricity prices in the system. The lower wholesale electricity prices benefit all consumers, including those without investment in any distributed technology. Distributed storage scheduling results in substantially lower integration of EES capacity in the electricity supply. Through arbitrage, storage minimizes the differential between on- and off-peak prices, thereby reducing electricity system costs. Less aggregated storage capacity implies a lower ability for the system operator to reduce electricity prices. Hence, in all scenarios, greater private electricity costs and lower private savings are observed relative to centralized scheduling. Table 2 summarizes the findings for the distributed scheduling.

3.1.1. Consumer's choice of technology and electricity tariffs

The lowest electricity cost in the no-technology case occurs under centralized coordination, Consumer Power and ToU tariffs (£420 p.a.), while the highest costs occur under distributed scheduling, Slow Progression, and static tariffs (£569 p.a.). With ToU tariffs, the EES system can provide 2–3% greater savings relative to static tariffs under distributed coordination compared with centralized coordination. Under ToU, the savings in the EES-only case are £99–126 under centralized coordination versus £101–140 under distributed coordination compared to "No technology" in the respective future scenario. This shows approximately 7% larger savings in distributed scheduling. As the distributed coordination scenario implies a less smoothened system demand, this leaves a greater ability for the consumer to take advantage between peak and off-peak price differentials.

The largest savings recorded in the EES-only case occurs under centralized coordination, Consumer Power, and ToU tariffs (£321 p.a.). Conversely, the lowest savings arise under distributed coordination, Slow Progression, and static tariffs (£569 p.a.).

If the consumer operates solar PV without EES (PV-only), the electricity bill will decline by 37–57% compared to the no-technology case, and by between 13 and 37% relative to EES-only. The lowest electricity costs for PV-only relate to centralized scheduling, Consumer Power and ToU tariffs (£244 p.a.), whereas the largest costs arise under distributed scheduling, Slow Progression, and static tariffs (£359 p.a.).

The combination of solar PV with EES implies a reduction in annual electricity costs by 81–88%, or by £476–506 annually. Therefore, the consumer reduces electricity costs by at a substantial rate of 60% compared to the PV-only case (£176–256 further savings annually). On average across the future energy system scenarios, ToU tariffs imply 12% larger savings relative to static tariffs for the consumer. In this case, annual electricity costs are between £68–73 p.a. and £71–80 p.a. in the centralized and distributed cases, respectively. When operating a PV-EES system, the consumer achieves maximum savings under centralized coordination,

Table 2
Annual electricity bills and possible savings (£ p.a.) for a typical consumer under distributed scheduling. The savings are relative to the base case: No technology, static tariff, and No Progression scenario.

Distributed scheduling		No Progression		Slow Progression		Consumer Power		Gone Green	
Tariff	Technology	Bill (£ p.a.)	Savings (£ p.a.)	Bill (£ p.a.)	Savings (£ p.a.)	Bill (£ p.a.)	Savings (£ p.a.)	Bill (£ p.a.)	Savings (£ p.a.)
A. Static	No technology	588	0	569	19	476	112	516	72
	EES	588	0	569	19	476	112	516	72
	PV	378	210	359	229	301	287	327	261
	PV-EES	116	472	103	485	83	505	91	497
B. ToU	No technology	559	29	541	47	442	146	491	97
	EES	419	169	406	182	341	247	370	218
	PV	321	267	309	279	256	332	281	307
	PV-EES	101	487	91	497	71	517	80	508

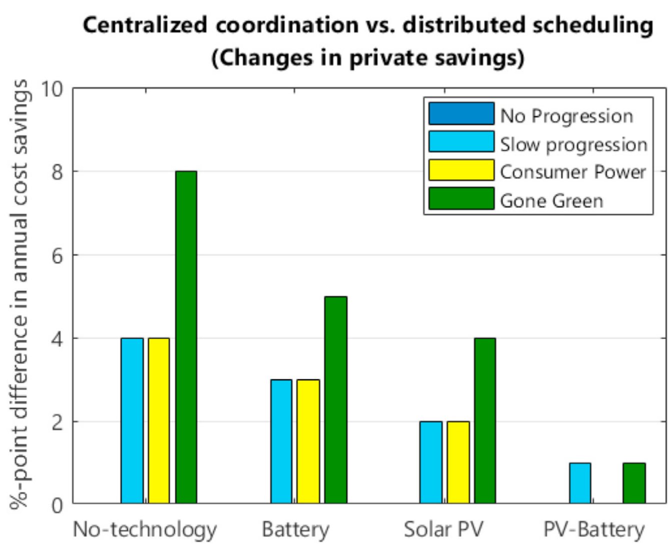

Fig. 5. Centralized coordination versus distributed scheduling of consumers' energy technologies under time-of-use the (ToU) electricity tariff. The values show the % savings of centralized coordination minus that of distributed scheduling relative to the base case (hence, positive values show that centralized coordination offers greater savings).

Consumer Power and ToU tariffs (£68 p.a.), whereas the lowest savings occur when scheduling occurs on a distributed basis, under Slow Progression and static tariffs (£103 p.a.).

Overall, for different technology mixes, a distributed coordination of energy storage in the electricity system, as well as Slow Progression, and static tariffs tend to minimize annual savings by the consumer. Conversely, central energy storage coordination, Consumer Power and ToU tariffs maximize savings.

3.2. Future energy scenarios

The results suggest that the centralized coordination of EES resources in the electricity system is always lead to greater savings (up to 11%) for a typical consumer, irrespective of the future evolution of the energy system. Yet the order of magnitude by which savings under centralized coordination are larger depends on the relationship between variable renewable energy capacity – mostly includes wind and PV generation – and flexible supply capacity, such as gas plants. If resources are mostly centrally coordinated, consumers can reduce annual electricity costs by 8–11% in Gone Green, by 4–5% in Slow Progression, and by 4–6% in Consumer Power, relative to distributed coordination.

The impact of centralized coordination of storage resources on the consumer's annual electricity costs generally increases with the level of variable renewable generation capacity in the electricity system while inversely related to level of flexible supply capacity. Savings to the consumer under centralized coordination are double in Gone Green relative to Slow Progression due to the higher variable renewable generation in the former case, which requires an aggregated storage for balancing variations.

Table 3 reports the ratio of variable renewable capacity to each unit of flexible generation capacity, as well as the change in the consumer's annual electricity costs (%) resulting from storage aggregation in the electricity system. There is a positive relationship between the share of variable renewables in the system, and the change in electricity prices due to centralized coordination. By dividing the latter by the former, a relatively constant relationship is observed, between 3 and 4%. Demand-side flexibility will be most valuable when supply is inflexible, leading to greater savings in the consumer's annual electricity cost under a more system-efficient coordination of storage resources. Yet the change in the electricity cost from coordination is small relative to the ratio between renewables and flexible supply.

3.3. Impact of additional storage deployments on private savings

Fig. 6 shows how additional electricity storage capacity is likely to affect savings from storage to a consumer with EES. In this specific analysis, we consider ToU tariffs only as they are shown to maximize the savings that storage can provide to consumers with solar PV. Additional (aggregated) storage capacity operating in the electricity system can decrease the differential between on- and off-peak electricity wholesale prices, which could in turn reduce the retail tariff on- and off-peak differential.

There is a quasi-exponential fall in the private savings as more electricity storage is installed and aggregated in the wider electricity system. An increase in aggregated storage capacity from 3 GW to 17 GW implies a 20% reduction in the private annual cost savings from storage to the consumer. These results do not hold if considering distributed coordination, as non-aggregated storage capacity has no effect on the marginal savings from private storage capacity.

4. Discussion

4.1. Private savings from storage and control scheme

This paper shows that the savings that a typical UK electricity consumer can achieve from their EES device could increase if most consumers in the electricity system allow an aggregator to coordinate their storage resources. When consumers' storage capacity is operated to minimize the private costs of these consumers, herding behaviour occurs, leading to charging the consumer EES devices at the same time of the day leading to higher electricity prices relative

Table 3
Ratio of variable renewable to flexible supply capacity (excluding storage), and relationship with savings from demand coordination.

Future energy scenario	Ratio of renewable energy capacity to flexible supply capacity	Change in annual electricity costs under central coordination (% p.a.)
Gone Green	2.62	−8.8%
Consumer Power	1.97	−5.3%
Slow Progression	1.81	−4.5%

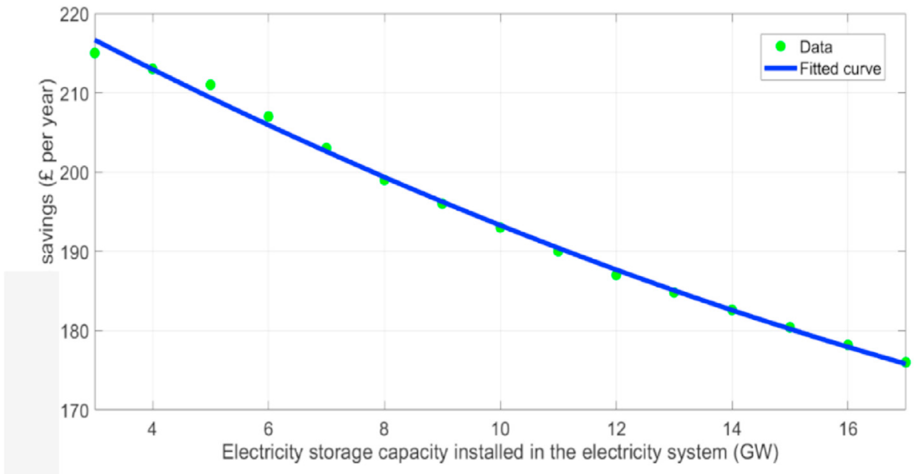

Fig. 6. Savings to the typical consumer due to their electricity storage relative to the installed electricity storage capacity in the electricity system. This analysis considers the centralized case with ToU tariffs.

to centralized coordination. These results are shown to hold true for different types of technologies and evolutions of the energy system.

Our findings confirm those of [28,50], and [35] who reported that social welfare increases if storage resources are centrally scheduled. Similarly, Castagneto Gissey et al. [27] compared centralized and distributed coordination and suggested that consumers could be nudged into giving away control of their storage devices to provide system benefits. They found that aggregation of EES has a lower electricity system cost compared to private operation by consumers. Our study enhances this work by considering how the private savings that consumers can expect from investing in storage could be affected by the way other consumers operate their storage devices.

The results also show the distributional effect of the centralized coordination on consumers. Those consumers owning flexible technologies such as EES and providing the aggregator with the capacity of their device for load balancing, make relatively lower bill savings compared to those consumers with “No technology”. For example, PV-EES owners make 0−2% additional savings in the centralized scheme while consumers with no technology 2−10%. This is mainly due to the lower electricity prices for all consumers in the centralized coordination compared to a distributed scheduling, which benefits the most consumers under static tariffs with no technology. Therefore, the regulator should put a policy in place for redistributing some of the system-level benefits back to the EES providers in the centralized coordination. In other words, the positive externality of aggregating distributed EES can be calculated, including lower electricity prices at peak times and lower grid congestion management fees, and a part of that can be used to incentivize EES owners participating in the aggregation scheme. The lack of such incentives can deteriorate the economic attractiveness of centralized coordination schemes for consumers [51−53].

4.2. Potential impact of system variables on the consumer savings

EES could provide numerous services to the electricity system [54,55], and the possibility for storage capacity to be aggregated can reduce the cost of electricity systems by decreasing peak demand and the need for expensive peaking plants. A few studies have shown the value of storage in high-renewable, inflexible power systems [12,34,56]. Studies considering the role of storage in the electricity system generally do not make a distinction between private and system benefits from EES, which we instead consider by considering the impacts of distributed and centralized coordination.

Our work suggests that storage will be more valuable to energy storers if variable renewable capacity is on average larger than the capacity of flexible supply resources such as gas power plants in the power system. When variable renewable capacity is large relative to flexible supply capacity, there is a shortage of flexibility on the supply-side, meaning that a system able to centrally coordinate more demand-side storage resources will be more valuable, and would produce more savings to consumers from their storage technology. Yet these insights must be checked against the possibility of distributed energy storage coordination to account for the likely scenario in which storage resources belonging to consumers are operated in a way that does not necessarily benefit the system, so long as it benefits the cost-minimizing consumer.

Many consumers would prefer to dispatch their storage resources to reduce their own electricity bills rather than to reduce costs to the wider system. Hence, previous studies may have tended to overestimate the utility of storage in reducing electricity prices by assuming large amounts of demand-side energy storage aggregation. As additional storage capacity is deployed, the lower gap in peak and off-peak electricity prices diminishes the potential benefits, sending a discouraging signal to the market for new investments. Hence, policymakers should closely monitor the flexibility requirements of the system and the willingness of consumers to provide flexibility services to the system. This can be done by internalizing the system-level benefits of EES, through introducing incentives for investment in EES. From modelling method perspective, this implies that models of the electricity system should account for the trade-offs between private and system benefits of energy storage aggregation.

Yet it is unlikely that consumers will allow an aggregator to control their resources at all unless they are paid a financial incentive to do so [57]. The decision by consumers to forego control of their storage resources could meaningfully reduce electricity wholesale prices [27]. This also entails the installation of smart meters and the access to the energy consumption data of private consumers, which they might be unwilling to share. The ability of aggregators and the System Operator to nudge consumers into providing such information could be key to the successful operation of aggregators.

The private savings that consumers can gain from their storage device will depend on the evolution of the electricity and energy systems. Consumers contemplating to invest in EES should not only be aware of the quantity of storage capacity deployed in the electricity system but should also monitor the level of renewables that this aggregated storage capacity is likely to meet. This information is important because it affects the operational savings from storage by consumers, hence the probability of them investing in the technology. This could also be a reason for the complexity of cost-benefit calculations by consumers and hence the current lack of EES deployments by domestic users [17,58].

Providing consumers with an understanding of how savings from their storage devices could be affected by numerous energy system conditions could improve consumer confidence in the technology and might facilitate deployments. It is more likely for such information to be useful if provided in the form of a software integrated into an easily accessible website that calculates savings from storage based on high temporal and spatial resolution models of the electricity system. Such a model would consider where on the system the consumer is based, as well as the consumer's electricity consumption patterns, among other factors. This would help inform the consumer's decision as to whether a financial case to invest in storage exists in their specific case, and to understand the relationship between their investment on distributed technologies and their overall support for any future energy pathway.

4.3. Additional storage in the electricity system and consumer savings

We demonstrate that a consumer could expect lower savings from their storage technology if a large amount of storage installed throughout the electricity system. Yet this only occurs if this capacity is subject to aggregation. Annual electricity cost savings from storage to a typical UK consumer could fall by more than 20% if EES capacity were to increase from 3 GW to 17 GW in the system.

The policy implication here is that the system operator should provide the data of the existing capacity of storage in the system, planned new storage installations, and the level of aggregation of these assets. This information should ideally be made public together with statistics about the fraction of these resources that are centrally coordinated as this is likely to impact the savings of consumers, lowering that compared to the case no storage deployments or aggregation occurred.

4.4. Drawbacks and future work

This paper focused on arbitrage using EES, and the value of storage to consumers in providing non-economic benefits such as energy security has not been considered. Similarly, the value that consumers could extract from their storage device by providing balancing or ancillary services to the grid have also been neglected. As electricity systems evolve, it will become increasingly important to assess the value of security and the potential provision of grid services through aggregation, as these are effectively substitutes to one another, while having synergies with energy arbitrage [23]. We simplified the representation of domestic consumers by considering a typical domestic electricity consumer with a representative solar PV production and electricity consumption pattern. Yet these factors may largely vary across consumers and geographical areas. Furthermore, we focused on the role of coordination in the determination of wholesale electricity prices. Yet to uncover the changes in retail tariffs, our modelling work would benefit from an analysis where prices are made depending on capital, fuel, and networks costs in relation to each consumer in the electricity system.

5. Conclusions

This study investigates the potential economic savings to a UK electricity consumer as a function of energy storage coordination scheme, i.e., central vs. distributed, as well as the system-wide impact of deployment of such storage devices. As more consumers, and the wider electricity system, adopt electricity storage technologies, herding behaviour could occur: many cost-minimizing consumers with an incentive to shift electricity demand to the same periods of low electricity prices, which will ultimately lead to an increased electricity demand and price peaks. Storage technologies already face multiple market barriers today. Hence, it is crucial to understand the impact of electricity market design on potential financial benefits of a storage owner (storer).

This paper examines the possible economic impact of owning a demand-side energy storage on the savings to a typical domestic consumer equipped with a solar PV microgeneration system. We conclude that pairing solar PV with storage could reduce electricity bills for a typical UK consumer by 80–88%. Yet the value of storage device is likely to increase if most electricity consumers allow an aggregator to coordinate their storage resources, thereby, reducing peak electricity demand resulting in more affordable electricity for all consumers. Our study shows that the benefits of consumers investing in energy storage is partly dependent on the ratio of variable renewable energy capacity to flexible supply capacity in the system. This ratio tends to improve savings from storage when the need for flexibility grows in the system.

This paper further investigates the relationship between savings to a typical UK electricity consumer using energy storage only for arbitrage versus the amount of aggregated storage capacity deployed by the electricity System Operator. A five-fold increase in the level of aggregated storage capacity can potentially lead to 20% lower savings to the consumer from their energy storage device. We show that consumers should expect diminishing marginal savings to the private utility of their storage device because of additional aggregated storage capacity if they pay time-dependent electricity tariffs, such as dynamic ToU tariffs. To maximize the value of the storage resources, the system operator should reduce the uncertainty in investing in storage by providing the consumers with the information about amount of deployed storage resources in the system, either centrally or individually coordinated. The scale of reduction in electricity bills of consumers depends on future electricity system evolutions too.

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.

Acknowledgments

This research was funded by the UK Engineering and Physical Research Council (EPSRC) through the Realising Energy Storage Technologies in Low-carbon Energy Systems (RESTLESS) project (EP/N001893/1), for which the authors are very grateful. The contribution by BZ have been partly supported by International Institute for Applied Systems Analysis (IIASA), and the RE-INVEST project “Renewable Energy Investment Strategies – A two-dimensional interconnectivity approach” funded by Innovation Fund, Denmark. The authors would also like to thank Professor Richard Green (Imperial College London) for useful suggestions.

Author statement

Conceptualization: B.Z., G.C.G., P.E.D., D.S. Methodology, Software, Data curation, and formal analysis: G.C.G., B.Z. Writing - Original Draft: B.Z., G.C.G. Writing - Review & Editing: B.Z. Visualization: B.Z., G.C.G. Supervision: P.E.D. Funding acquisition: G.C.G., P.E.D.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.energy.2021.121443.

References

[1] Pfenninger S, Staffell I. Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 2016;114: 1251–65. https://doi.org/10.1016/j.energy.2016.08.060.

[2] Castagneto Gissey G, Zakeri B, Dodds PE, Subkhankulova D. Evaluating consumer investments in distributed energy technologies. Energy Pol 2021;149: 112008. https://doi.org/10.1016/j.enpol.2020.112008.

[3] Shrivastava A, Saini DK, Pandit M. Distribution grid parameter variation due to solar PV power integration. Int J Renew Energy Resour 2020;10:1125–32.

[4] Fernández G, Galan N, Marquina D, Martínez D, Sanchez A, López P, et al. Photovoltaic generation impact analysis in low voltage distribution grids. Energies 2020;13. https://doi.org/10.3390/en13174347.

[5] Sweco. Distributed electricity production and self-consumption in the Nordics. 2019.

[6] Bagalini V, Zhao BY, Wang RZ, Desideri U. Solar PV-battery-electric grid-based energy system for residential applications: system configuration and viability. Research 2019;2019. https://doi.org/10.34133/2019/3838603.

[7] Klingler AL. Self-consumption with PV + Battery systems: a market diffusion model considering individual consumer behaviour and preferences. Appl Energy 2017;205:1560–70. https://doi.org/10.1016/j.apenergy.2017.08.159.

[8] Zhang J, Cho H, Luck R, Mago PJ. Integrated photovoltaic and battery energy storage (PV-BES) systems: an analysis of existing financial incentive policies in the US. Appl Energy 2018;212:895–908. https://doi.org/10.1016/j.apenergy.2017.12.091.

[9] Zakeri B, Cross S, Dodds PE, Gissey GC. Policy options for enhancing economic profitability of residential solar photovoltaic with battery energy storage. Appl Energy 2021;290:116697. https://doi.org/10.1016/j.apenergy.2021.116697.

[10] Mulenga E, Bollen MHJ, Etherden N. A review of hosting capacity quantification methods for photovoltaics in low-voltage distribution grids. Int J Electr Power Energy Syst 2020;115. https://doi.org/10.1016/j.ijepes.2019.105445.

[11] do Nascimento ÁDJ, Rüther R. Evaluating distributed photovoltaic (PV) generation to foster the adoption of energy storage systems (ESS) in time-of-use frameworks. Sol Energy 2020;208:917–29. https://doi.org/10.1016/j.solener.2020.08.045.

[12] Denholm P, Jorgenson J, Jenkin T, Palchak D, Kirby B, Malley MO, et al. The value of energy storage for grid applications. Natl Renew Energy Lab 2013;37.

[13] Akhil AA, Huff G, Currier AB, Kaun BC, Rastler DM, Chen SB, et al. DOE/EPRI 2015 electricity storage handbook in collaboration with NRECA. Sandia Natl Lab; 2015.

[14] Schmidt O, Hawkes A, Gambhir A, Staffell I. The future cost of electrical energy storage based on experience rates. Nat Energy 2017;2:1–8. https://doi.org/10.1038/nenergy.2017.110.

[15] Uddin K, Gough R, Radcliffe J, Marco J, Jennings P. Techno-economic analysis of the viability of residential photovoltaic systems using lithium-ion batteries for energy storage in the United Kingdom. Appl Energy 2017;206:12–21. https://doi.org/10.1016/j.apenergy.2017.08.170.

[16] Diezmartínez CV. Clean energy transition in Mexico: policy recommendations for the deployment of energy storage technologies. Renew Sustain Energy Rev 2021;135:110407. https://doi.org/10.1016/j.rser.2020.110407.

[17] Hossain E, Faruque HMR, Sunny MSH, Mohammad N, Nawar N. A comprehensive review on energy storage systems: types, comparison, current scenario, applications, barriers, and potential solutions, policies, and future prospects. Energies 2020;13:3651. https://doi.org/10.3390/en13143651.

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

[19] Parra D, Patel MK. Effect of tariffs on the performance and economic benefits of PV-coupled battery systems. Appl Energy 2016;164:175–87. https://doi.org/10.1016/j.apenergy.2015.11.037.

[20] Rodrigues DL, Ye X, Xia X, Zhu B. Battery energy storage sizing optimisation for different ownership structures in a peer-to-peer energy sharing community. Appl Energy 2020;262:114498. https://doi.org/10.1016/j.apenergy.2020.114498.

[21] Stephan A, Battke B, Beuse MD, Clausdeinken JH, Schmidt TS. Limiting the public cost of stationary battery deployment by combining applications. Nat Energy 2016;1. https://doi.org/10.1038/nenergy.2016.79.

[22] Gardiner D, Schmidt O, Heptonstall P, Gross R, Staffell I. Quantifying the impact of policy on the investment case for residential electricity storage in the UK. J Energy Storage 2020;27:101140. https://doi.org/10.1016/j.est.2019.101140.

[23] Pusceddu E, Zakeri B, Castagneto Gissey G. Synergies between energy arbitrage and fast frequency response for battery energy storage systems. Appl Energy 2021;283:116274. https://doi.org/10.1016/j.apenergy.2020.116274.

[24] Zakeri B, Syri S. Value of energy storage in the Nordic Power market - benefits from price arbitrage and ancillary services. Int. Conf. Eur. Energy Mark. EEM 2016;2016– July. https://doi.org/10.1109/EEM.2016.7521275.

[25] Fingrid. Reserves and balancing power - Fingrid. https://www.fingrid.fi/en/electricity-market/reserves_and_balancing/. [Accessed 12 December 2020].

[26] Merten M, Rücker F, Schoeneberger I, Sauer DU. Automatic frequency restoration reserve market prediction: methodology and comparison of various approaches. Appl Energy 2020;268:114978. https://doi.org/10.1016/j.apenergy.2020.114978.

[27] Castagneto Gissey G, Subkhankulova D, Dodds PE, Barrett M. Value of energy storage aggregation to the electricity system. Energy Pol 2019;128:685–96. https://doi.org/10.1016/j.enpol.2019.01.037.

[28] Jia L, Tong L. Renewables and storage in distribution systems: centralized vs. Decentralized integration. IEEE J Sel Area Commun 2016;34:665–74. https://doi.org/10.1109/JSAC.2016.2525638.

[29] Chaminda Bandara WG, Godaliyadda GMRI, Ekanayake MPB, Ekanayake JB. Coordinated photovoltaic re-phasing: a novel method to maximize renewable energy integration in low voltage networks by mitigating network unbalances. Appl Energy 2020;280. https://doi.org/10.1016/j.apenergy.2020.116022.

[30] Borenstein S. Private net benefits of residential solar pv: the role of electricity tariffs, tax incentives, and rebates. J Assoc Environ Resour Econ 2017;4: S85–122. https://doi.org/10.1086/691978.

[31] Balta-Ozkan N, Yildirim J, Connor PM, Truckell I, Hart P. Energy transition at local level: analyzing the role of peer effects and socio-economic factors on UK solar photovoltaic deployment. Energy Pol 2021;148:112004. https://doi.org/10.1016/j.enpol.2020.112004.

[32] Mundaca L, Samahita M. What drives home solar PV uptake? Subsidies, peer effects and visibility in Sweden. Energy Res Soc Sci 2020;60:101319. https://doi.org/10.1016/j.erss.2019.101319.

[33] Tu Q, Mo J, Betz R, Cui L, Fan Y, Liu Y. Achieving grid parity of solar PV power in China- the role of Tradable Green Certificate. Energy Pol 2020;144:111681. https://doi.org/10.1016/j.enpol.2020.111681.

[34] Trust Carbon. Energy storage report: can storage help reduce the cost of a future UK electricity system? Carbon Trust; 2016. https://www.carbontrust.com/resources/energy-storage-report-can-storage-help-reduce-the-cost-of-a-future-uk-electricity-system. [Accessed 17 October 2020].

[35] Varghese S, Sioshansi R. The price is right? How pricing and incentive mechanisms in California incentivize building distributed hybrid solar and energy-storage systems. Energy Pol 2020;138:111242. https://doi.org/10.1016/j.enpol.2020.111242.

[36] de Sisternes FJ, Jenkins JD, Botterud A. The value of energy storage in decarbonizing the electricity sector. Appl Energy 2016;175:368–79. https://doi.org/10.1016/j.apenergy.2016.05.014.

[37] Katz ML, Shapiro C. Network externalities, competition, and compatibility. Am Econ Rev 1985;75:424–40.

[38] Burger S, Chaves-Ávila JP, Batlle C, Pérez-Arriaga IJ. A review of the value of aggregators in electricity systems. Renew Sustain Energy Rev 2017;77: 395–405. https://doi.org/10.1016/j.rser.2017.04.014.

[39] Sousa T, Soares T, Pinson P, Moret F, Baroche T, Sorin E. Peer-to-peer and community-based markets: a comprehensive review. Renew Sustain Energy Rev 2019;104:367–78. https://doi.org/10.1016/j.rser.2019.01.036.

[40] Obaid ZA, Cipcigan LM, Muhssin MT, Sami SS. Control of a population of battery energy storage systems for frequency response. Int J Electr Power Energy Syst 2020;115:105463. https://doi.org/10.1016/j.ijepes.2019.105463.

[41] Carvallo JP, Zhang N, Murphy SP, Leibowicz BD, Larsen PH. The economic value of a centralized approach to distributed resource investment and operation. Appl Energy 2020;269:115071. https://doi.org/10.1016/j.apenergy.2020.115071.

[42] Ahmadi M, Adewuyi OB, Danish MSS, Mandal P, Yona A, Senjyu T. Optimum

coordination of centralized and distributed renewable power generation incorporating battery storage system into the electric distribution network. Int J Electr Power Energy Syst 2021;125:106458. https://doi.org/10.1016/j.ijepes.2020.106458.
[43] Sanders D, Hart A, Ravishankar M, Strbac G, Aunedi M, Pudjianto D, et al. An analysis of electricity system flexibility for Great Britain. 2016.
[44] National Grid. Future energy scenarios. National Grid ESO; 2017. https://www.nationalgrideso.com/future-energy/future-energy-scenarios. [Accessed 26 October 2020].
[45] UCL. UK times. UCL ENERGY INSTITUTE MODELS - UCL — University College London; 2020. https://www.ucl.ac.uk/energy-models/models/uk-times. [Accessed 13 December 2020].
[46] Subkhankulova D. Exploring future opportunities and challenges of demand side management with agent based modelling. University College London; 2018.
[47] Ofgem. Feed-in tariff (FIT) rates | ofgem. 2020. https://www.ofgem.gov.uk/environmental-programmes/fit/fit-tariff-rates. [Accessed 26 October 2020].
[48] National Statistics. Quarterly energy prices - gov.UK. 2020. https://www.gov.uk/government/collections/quarterly-energy-prices. [Accessed 26 October 2020].
[49] Rampazzo M, Luvisotto M, Tomasone N, Fastelli I, Schiavetti M. Modelling and simulation of a Li-ion energy storage system: case study from the island of Ventotene in the Tyrrhenian Sea. J Energy Storage 2018;15:57—68. https://doi.org/10.1016/j.est.2017.10.017.
[50] He X, Delarue E, D'haeseleer W, Glachant J-M. A novel business model for aggregating the values of electricity storage. Energy Pol 2011;39:1575—85.
[51] Sorrell S. Reducing energy demand : a review of issues , challenges and approaches. Renew Sustain Energy Rev 2015;47:74—82. https://doi.org/10.1016/j.rser.2015.03.002.
[52] Winfield M, Shokrzadeh S, Jones A. Energy policy regime change and advanced energy storage: a comparative analysis. Energy Pol 2018;115: 572—83. https://doi.org/10.1016/j.enpol.2018.01.029.
[53] Child M, Haukkala T, Breyer C. The role of solar photovoltaics and energy storage solutions in a 100% renewable energy system for Finland in 2050. Sustain Times 2017;9. https://doi.org/10.3390/su9081358.
[54] Kalkbrenner BJ. Residential vs. community battery storage systems — consumer preferences in Germany. Energy Pol 2019;129:1355—63. https://doi.org/10.1016/j.enpol.2019.03.041.
[55] Mejia C, Kajikawa Y. Emerging topics in energy storage based on a large-scale analysis of academic articles and patents. Appl Energy 2020;263:114625. https://doi.org/10.1016/j.apenergy.2020.114625.
[56] Conejo AJ, Sioshansi R. Rethinking restructured electricity market design: lessons learned and future needs. Int J Electr Power Energy Syst 2018;98: 520—30. https://doi.org/10.1016/j.ijepes.2017.12.014.
[57] Obi M, Slay T, Bass R. Distributed energy resource aggregation using customer-owned equipment: a review of literature and standards. Energy Rep 2020;6:2358—69. https://doi.org/10.1016/j.egyr.2020.08.035.
[58] Castagneto Gissey G, Dodds PE, Radcliffe J. Market and regulatory barriers to electrical energy storage innovation. Renew Sustain Energy Rev 2018;82: 781—90. https://doi.org/10.1016/j.rser.2017.09.079.