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A new dawn for energy storage: An interdisciplinary legal and techno-economic analysis of the new EU legal framework

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ABSTRACT

Beyond the hitherto high cost of storage technologies, regulatory and market barriers such as lack of definition, double grid charges and unclear ownership rules have hindered their deployment. These barriers, however, have been largely overlooked in energy modelling research, calling for new interdisciplinary research. In 2019, the new EU electricity market directive was released with energy storage as a central element. Against this background, we study the impact of the new EU legal framework on the value of energy storage across 12 countries using techno-economic modelling informed by legal analysis and expert interviews. We conclude that the new legal regime fits for behind-the-meter batteries which could become widespread across Europe, considering their important value creation. This could also be the case for community storage, especially if national transpositions of the new legal regime prevent double grid charges or at least, moderate them. Legal certainty is created by prohibiting network operators to operate energy storage, but we argue that benefit stacking including applications which support electricity grids would only be possible if network operators set up transparent flexibility markets for the interested parties.

1. Introduction

Energy storage is becoming a key component of energy systems as the energy transition progresses. The global energy sector is currently experiencing a fundamental shift and power systems are gradually transitioning from unidirectional and centralized to multidirectional and distributed systems (Parag and Sovacool, 2016; Parra et al., 2017). The main driver of this shift is the penetration of renewable energy technologies such as solar and wind, for which the installed capacity has grown exponentially since the beginning of the 21st century, reaching 713 GW and 733 GW respectively in 2020 (IRENA, 2021). However, they cannot supply electricity on demand, and this hinders their value (Braff et al., 2016; Gupta et al., 2020; Parra and Patel, 2019). Storage technologies can provide flexibility, increase the value of renewable energy technologies, and accelerate their penetration to reach net-zero decarbonisation (Gupta et al., 2020; Ziegler et al., 2019; Schill, 2020; Haas et al., 2022).

In addition to pumped hydro storage (PHES), which still accounts for 94% of energy storage capacity worldwide (equivalent to 9000 GWh) (Barbour et al., 2016; International Hydropower Association (IHA), 2020; IRENA, 2017), there are various storage technologies available on the market which respond to different principles, namely mechanical (e.g., compressed air energy storage), electrochemical (e.g., lithium-ion batteries), electrical (e.g., supercapacitors), thermal (e.g., molten salts) and chemical (e.g., hydrogen) (Luo et al., 2015), and have different technology readiness levels (IRENA, 2017; International Energy Agency, 2014). Lithium-ion batteries dominate storage additions at the moment, e.g., 4 GW installed by 2018 (Pavarini, 2019), with behind-the-meter and frequency control being key applications (Parra and Patel, 2019), but they can deliver more applications[1] to increase their value (IRENA, 2015). In a carbon-constrained world, most scenarios from research institutions and international organisations project a massive deployment of storage technologies (Victoria et al., 2019; de Sisternes et al., 2016; Rinaldi et al., 2020), assuming marked cost reductions by 2030, e.g., 70% and 40% cost reductions for lithium-ion batteries (Schmidt et al., 2017) and polymer electrolyte membrane (PEM) electrolysers (IRENA, 2020), respectively.

Despite this promising outlook, the lack of an enabling legal

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[1] For example, a total of 14 applications for batteries were identified by the International Renewable Energy Agency (IRENA).

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framework was identified as a prime barrier to energy storage investment and innovation (Parag and Sovacool, 2016; Castagneto Gissey et al., 2018; Gährs and Knoefel, 2020; Schmitt and Sanford, 2018; Crossley, 2013; Schreiber, 2020; Stephan et al., 2016). In Europe, the 2009 Electricity Directive (hereinafter 2009 E-Directive) hindered energy storage finance and investment decisions (Directive, 2009). First, storage was not defined and some European (EU) countries, like Italy, adopted their own definition while others, like Germany, simply ignored energy storage (Schreiber, 2020; Kreeft and Mauger, 2021; Kreeft, 2018). Secondly, industry competition was challenged by the lack of a harmonised set of legal frameworks among various EU countries (Penttinen et al., 2020). Some EU countries like Italy allowed network operators to own and operate storage (although only under very limited circumstances), while others, such as the United Kingdom (UK), prohibited them to develop these activities based on ownership unbundling rules (i.e. the separation of transport and distribution activities from production and supply in a liberalised electricity market) from the 2009 E-Directive (Kreeft and Mauger, 2021). Thirdly, the lack of a clear regime (understood as the legal framework in force) hindered the value of energy storage, which was often considered both as generation (when discharging to the grid) and as consumption (when charging from the grid) (Penttinen et al., 2020; Dalton, 2019). As a result, storage plants then paid grid charges and some additional levies twice, with this reducing their marketing competitiveness in comparison to traditional means of providing flexibility such as flexible generation (Castagneto Gissey et al., 2018). Finally, the legal framework and related market conditions were frequently not suitable to remunerate storage technologies performing several applications, also referred to as benefit stacking (Parra and Patel, 2019; Schmitt and Sanford, 2018; Stephan et al., 2016; Englberger et al., 2020; Lund, 2020).

These four key regulatory barriers (Dalton, 2019), namely lack of definition, unclear ownership and operation rules, double charges and inadequate legal framework for benefit stacking have slowed down storage penetration, hindering innovation in storage technologies, e.g., learning-by-doing, which triggers cost reductions due to learning spill-overs during production and use (Arrow, 1962; Schmidt et al., 2016). To address these barriers and other related aspects, the European Union recast the Electricity Directive in 2019 (hereinafter 2019 E-Directive), which is the cornerstone of the new EU regime for the transition to a renewable-powered European energy system and includes a new framework for energy storage (Kreeft and Mauger, 2021; Penttinen et al., 2020; Goldberg and Bille, 2020; Directive, 2019). Furthermore, the 2018 Renewable Energy Directive (hereinafter 2018 RES-Directive) emphasises in its recital 60 that energy storage should be supported to facilitate the integration of renewable energy technologies (Directive, 2018).

Despite the acknowledged implications of the legal framework on the attractiveness of energy storage investments and therefore its final deployment, it has been largely ignored in techno-economic and energy system modelling of energy storage (Sioshansi et al., 2022). This is, for example, the case for grid charges, which are typically neglected in studies assessing the value and profitability of storage technologies embedded in the electricity system and performing different types of applications (Braff et al., 2016; Stephan et al., 2016; Balducci et al., 2018; Barbour et al., 2012, 2018), owing to the high uncertainty in their type and value for both charging and discharging across various countries. Specific grid charges and levies for electricity storage depend on the connection point (i.e. voltage level), can include different types of taxes, and finally, apply to the charge and/or discharge processes. Although several studies have analysed the impact of electricity tariffs including grid charges and financial incentives for behind-the-meter storage (Peña-Bello et al., 2019; Sani Hassan et al., 2017; Young et al., 2019; Schwarz et al., 2019), we are not aware of any study which analyses the legal framework, but also quantifies its impact on energy storage at various relevant deployment scales, namely behind-the-meter, community, distributed (e.g., embedded with transformers at low voltage distribution grids or at the medium voltage) and bulk (at high voltage). Benefit stacking was the focus of Baumgarte et al. who evaluated 28 possible business models (Baumgarte et al., 2020), Englberger et al. who optimised the performance of a battery combining applications in Germany (Englberger et al., 2020), and Stephan et al. who proposed it as strategy to mitigate risk (Stephan et al., 2016). However, none of these studies discussed benefit stacking for various storage deployment scales in connection with ownership models and grid charges. Furthermore, most deployment scenarios rely exclusively on cost trajectories which are used as input data for energy system models (e.g., social planners) (Victoria et al., 2019; Rinaldi et al., 2020; Sepulveda et al., 2018), and system-dynamic simulation models (Beuse et al., 2020), but we argue that the legal framework should be considered to understand the final scale and associated ownership of storage deployment, e.g., distributed versus bulk.

In this article, we address this gap and show qualitatively and quantitatively, as well as across locations, the impact of the legal framework on energy storage ownership, value and competitiveness among various relevant deployment scales, namely behind-the-meter, community, distributed and bulk. We consider energy storage for electricity applications, but also including power-to-gas and power-to-heat, i.e. applications which impact the electricity system either at the moment of charging or discharging, for instance by using surplus solar photovoltaics (PV) or wind electricity to produce synthetic gases or heat. We compare the optimised value of community batteries performing PV self-consumption and PHES performing electricity arbitrage with existing grid charges across 12 European countries based on available data, namely Austria, Belgium, France, Germany, Greece, Ireland, Italy, Portugal, Spain, Sweden, Switzerland and the UK. Therefore, we cover several regions with different levels of solar resource availability, electricity demand, electricity prices and grid charges and we use country-specific data accounting for their intrinsic daily and seasonal variations. Our contribution to the field relies on the integration of legal analysis and energy modelling optimisation informed by semi-structured interviews of key actors active in the energy storage industry such as technology developers, aggregators and network operators (see Tables S1–S14 in Section S1 as well as Supplementary Note 2 of the SI). While we focus on Europe considering relevant recent legal developments, our conclusions are useful to other geographies, e.g., the U.S. and Australia, where regulatory barriers to energy storage also exist (Schmitt and Sanford, 2018; Soliman Hunter and Taylor, 2020; Sue et al., 2014; Sakti et al., 2018a; Tiwari et al., 2021).

Building upon this introduction and literature review as well as on Section 2, this study is organised to describe and analyse in depth four important regulatory issues: (i) definition of energy storage, (ii) ownership and operation rules, (iii) double charges, and (iv) benefit stacking. Next, we critically discuss the impacts and consequences of regulatory changes in the context of the new 2019 E-Directive on energy storage, and we highlight remaining issues. Finally, we establish key implications for industry, policy makers and academics.

2. Input data and methods

To understand the impact of the new 2019 E-Directive on the value of energy storage, we propose an interdisciplinary methodology comprising expert interviews, legal analysis and techno-economic modelling and optimisation. Interviews were used to delimit the scope of the study, i.e. to identify the regulatory issues to be analysed in depth, as well as to discuss the modelling results. The legal analysis follows the socio-legal methodology, considering the legal provisions and their applicability in society. In our case, the study focuses on EU law and its application to energy storage and benefit stacking. Modelling results are then used to quantify the implications of the new legal regime on the value of energy storage. Our methodology is based on the following choices: i) regarding storage technologies, we select PHES, which is the most mature technology still dominating world capacity and lithium-ion batteries which are currently dominating capacity additions and are expected to play a major role for the energy transition; ii) regarding storage applications to study grid charges, we select baseline applications for PHES and lithium-ion batteries, namely electricity arbitrage and an increase of PV self-consumption, also considering that related electricity prices are open-source. This is not the case yet for frequency control prices despite the European Network of Transmission System Operators for Electricity (ENTSO-E) is now targeting them (e.g., frequency control prices are available for countries such as Belgium and Austria, but this is not yet the case for others countries such as Greece and Spain); and iii) regarding European countries, we select countries based on availability of input data such as grid charges, electricity demand profiles and electricity prices. Finally, we use 2016 as reference year to determine the value of energy storage in our models with a temporal resolution of 1 h. This study uses electricity prices prior the exceptional COVID-19 pandemic, and the war between Ukraine and Russia. Considering that the revenue generated by storage technologies performing electricity arbitrage and maximising PV self-consumption is proportional to electricity prices, while grid charges are mainly dependant on use of the grid infrastructure, provision of ancillary services and losses (TenneT), the net revenue of storage technologies performing electricity arbitrage and maximising PV self-consumption can be significantly higher during this exceptional period.

2.1. Interviews and legal analysis

Semi-structured interviews of key actors active in the energy storage industry such as technology developers, aggregators and network operators (see Tables S1–S14 in Section S1 and Supplementary Note 2 of the SI) were used to: (i) identify the major regulatory issues for energy storage according to these actors; (ii) understand the position of various types of stakeholders on the 2019 E-Directive; and (iii) complement our techno-economic results to build our conclusions. Six semi-structured interviews were conducted with representatives from the EU energy industry via virtual meetings during summer 2020. The interviewees, their role, and description of the organisation where they work are given in Table S1, with the formulated questions shown in Tables S–2. All the answers are listed in Tables S2–S14. Finally, Supplementary Note 2 provides for the general position of the various actors as well as some specific stances on the four identified regulatory barriers.

2.2. Optimisation of energy storage (PHES) performing electricity arbitrage in wholesale markets

The optimisation of the performance of price-taker energy storage plants performing electricity arbitrage based on a set of future electricity prices has already been solved and validated in the previous literature. Connolly et al. (2011) and Barbour et al. (2012) provided an efficient method and algorithm which is considered in this study. We use historical wholesale price data, which is the equivalent of perfect forecasting and by this reasoning, using historical price data provides the upper boundary of the arbitrage revenue available to a given storage device for that particular timeframe (i.e. a storage operator will never be able to gain more than the upper boundary arbitrage revenue deduced here). Mathematically, maximising the revenue of a storage plant performing electricity arbitrage, Rev_{arb}, can be framed as follows in *Equation* 1. Here, $p_h = (p_1, p_2, \ldots p_n)$ is a vector of hourly (h) electricity prices over the time horizon of 1 yr (denoted as n) corresponding to the discrete time periods $(t_1, t_2, \ldots t_n)$. Similarly, $E_h^{network} = (E_1^{network}, E_2^{network}, \ldots E_n^{network})$ is a vector of the energy output of the ES system.

To just focus on the storage performance, this optimisation is subject to constraints related to the physical properties of the storage plant, while constraints related to the electricity network are not considered. The first constraint implies that the energy stored must lie between 0 and the specified maximum storage capacity as shown in Equation 2. The second constraint given in Equation 3 states that the change in storage level must lie between the maximum allowable charge and discharge, acknowledging the charge and discharge efficiency, respectively, integrated over the duration of the time period, which corresponds to 1 h in our analysis.

The relationship between the energy contained in the storage plant at time t_i and time t_{i+1} is given by *Equation* 4:

The electricity charged from the network ($E_h^{network}$ is positive) or discharged to the network ($E_h^{network}$ is negative) can then be related to $\Delta E_h^{storage}$ by *Equation* 5 and *Equation* 6. In this manner, PHES has an efficiency penalty of $\eta_{charge}\eta_{discharge} = \eta_R$. The round-trip efficiency assumed for PHES together with the power and energy capacities are given in Table S15.

Fig. 1 is a box plot of the wholesale electricity prices across the various countries. Given a set of discrete wholesale electricity prices, the maximum revenue is found by locating the minimum and maximum prices in the time-series, and scheduling the storage plant to charge with the maximum possible energy at the minimum price period and discharge this same amount times the efficiency of the storage device at the maximum price period, provided this action is profitable (i.e. $p_{max} > p_{min}/\eta_R$) and considering the constraints above. Once constraints prohibit any further charging or discharging at a particular period, that period is no longer considered and the next minimum or maximum period is located and considered.

Finally, we levelise the upper revenue by dividing it by the storage discharge (corresponding to negative values of $E_h^{network}$) using *Equation* 7. Moreover, using *Equation* 7 with the cost associated with grid charges in the enumerator, we also levelise the cost associated with grid charges to compare it with the levelized value.

2.3. Optimisation of community energy storage performing PV self-consumption

A community battery is used as a representative case of energy storage serving a group of consumers when embedded to a local distribution network, i.e. “in front of the meter”. The optimal dispatch of a battery performing PV self-consumption (i.e. without charging from the electricity grid) was already presented and validated in the previous literature, e.g., Quoilin et al. (2016) and Peña-Bello et al. (2019). Next, we present the energy balance assuming a temporal resolution of 1 h which is needed to maximise PV self-consumption with the help of a community battery based on the algorithms presented in these two papers. In the various equations below, the various terms always refer to the community aggregated values, e.g., the community PV generation, community electricity demand and community battery discharge.

The objective is to maximise the PV self-consumption revenue of a community battery on an annual basis, Rev_{PVSC}, which is given by *Equation 8*, where E_{batdh} is the demand met by the battery system, E_{PVbath} is the PV electricity charge of the battery, for the hour h, P_i is the import electricity price (retail tariff), P_e is the price of the electricity export to the grid (feed-in tariff, FiT), and n is the number of hours in a year (8760). All the relevant input data such as PV generation, electricity demand and electricity prices are given for the various countries in Table 1, while Fig. 2 shows histograms of the annual electricity consumption of the 20 houses used to build an energy community depending on the country.

The PV generation balance is given by *Equation* 9 where E_{PVdh} is the PV generation supplied to the demand load; E_{PVbath} is the PV generation supplied to the battery and $E_{PVgridh}$ is the PV generation exported to the grid.

The electricity demand balance is given by *Equation* 10 where E_{PVdh} is the PV generation supplied to the demand load, E_{batdh} is the demand met by the battery system and E_{griddh} is the electricity grid import for the demand load.

The balance of the community battery is given by *Equation* 11 and

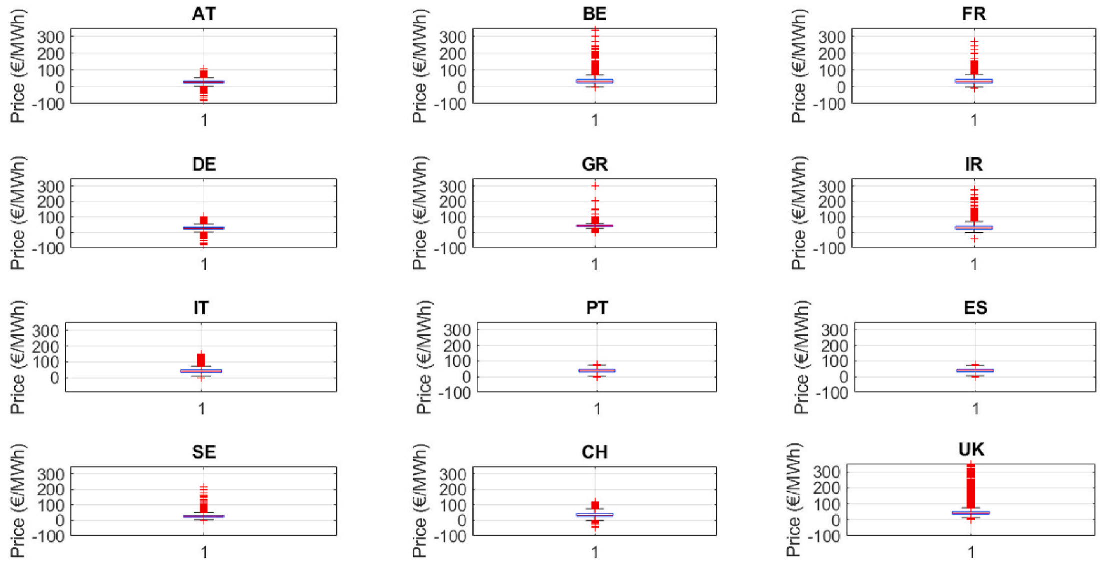

Fig. 1. Boxplots of wholesale electricity prices across 12 European countries in 2016. Input data retrieved from ENTSO-E (The European Network of Transmission, 2017a).

Table 1
Input data used to model the performance of community batteries performing PV self-consumption across the 12 European countries. We used monitored electricity demand data from Germany, Ireland, Portugal, Switzerland, and the UK, as well as dedicated modelled electricity demand data from Greece. For countries where monitored or modelled electricity demand data are not open source, we use demand profiles from the closest neighbouring country while still matching the average electricity consumption of the target country, e.g., Portugal for Spain, considering that the value of batteries performing PV self-consumption (and other consumer applications like demand load-shifting) is more affected by the annual electricity consumption than the specific electricity demand shape (Parra and Patel, 2019; Peña-Bello et al., 2020).

Time	Retail price (€/kWh) (EUROSTAT, 2016a)	Average wholesale price (€/kWh) (The European Network of Transmission, 2017b)	Average PV capacity factor (%) (Pfenninger and Staffell)	Average electricity consumption (kWh p. a.)	Electricity demand Source
AT	0.20	0.03	13.7	4620	Adapted from metered German electricity demand data (Tjaden et al., 2015)
BE	0.25	0.04	12.3	3760	Adapted from metered Dutch electricity demand data (Liander. Open data, 2013)
FR	0.17	0.04	12.4	5425	Adapted from metered Swiss electricity demand data (Peña-Bello et al., 2019)
DE	0.3	0.03	13.9	3694	Metered German electricity demand data (Tjaden et al., 2015)
GR	0.17	0.04	16.3	4471	Generated by the DREEM model (Stavrakas and Flamos, 2020). All building specifications and parameters were taken according the EU Online webtool "TABULA".
IR	0.23	0.03	10.8	4500	Metered Irish electricity demand (Irish Social Science Data Archive (ISSDA), 2010)
IT	0.23	0.04	15.4	2651	Adapted from metered Swiss electricity demand data (Peña-Bello et al., 2019)
PT	0.24	0.04	16.4	3114	Metered Portuguese electricity demand data (Gonçalo Artur Duarte Pereira and Santos Silva, 2012)
ES	0.22	0.04	16.7	3790	Adapted from metered Portuguese electricity demand data (Gonçalo Artur Duarte Pereira and Santos Silva, 2012)
SE	0.19	0.03	9.9	9601	Adapted from metered Dutch electricity demand data (Liander. Open data, 2013)
CH	0.18	0.04	15.1	5103	Metered Swiss electricity demand data (Peña-Bello et al., 2019)
UK	0.20	0.03	10.9	3666	Metered UK electricity demand data (Parra and Patel, 2019)

Equation 12, where E_{bat} is the electricity exchanged by the battery. *Equation* 13 provides the battery state of charge, SOC_{bath}, as a function of the *SOC* in the previous hour SOC_{bath-1}, the electricity exchanged by the battery, E_{bath}, and the battery capacity C_{bath}.

The previous electricity balance is subject to the following constraints given by *Equation* 14, *Equation* 15 and *Equation* 16 for the *SOC*, maximum battery discharge ($E_{bat_{dismax}}$) and maximum battery charge ($E_{bat_{charmax}}$), respectively.

Furthermore, there is not any electricity import and/or battery discharge for the community if there is PV surplus to the grid as shown in *Equation* 17 and *Equation* 18, respectively.

Finally, we levelise the upper revenue by dividing it by the storage discharge using *Equation* 19.

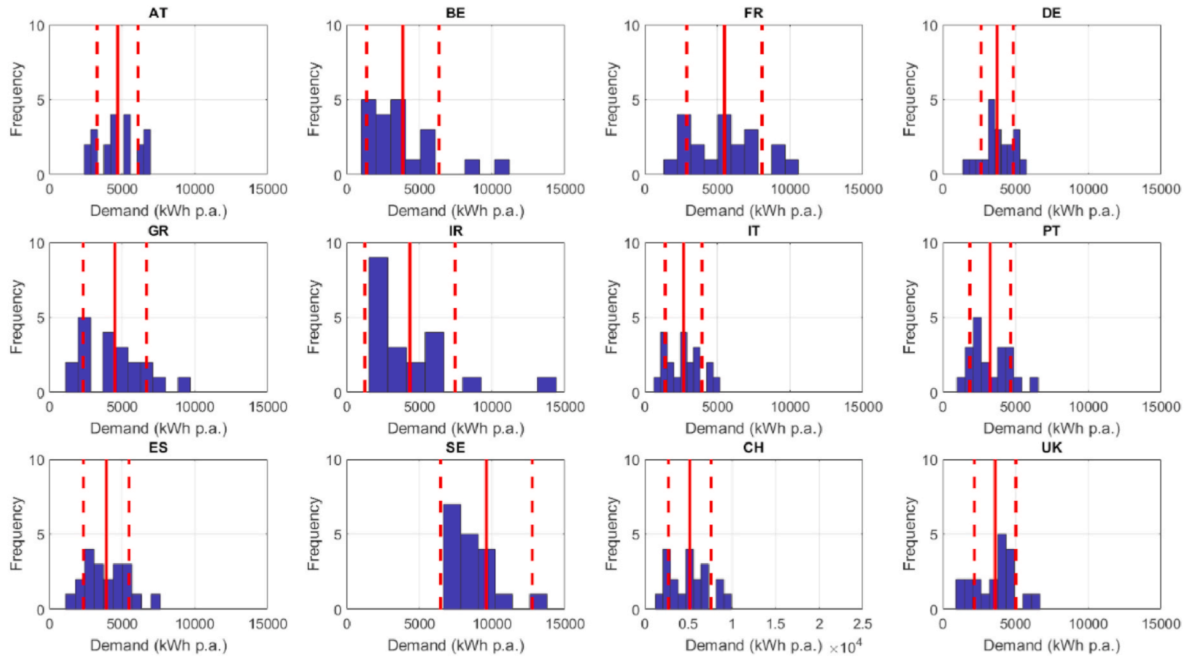

Fig. 2. Distribution of the average annual consumption for the 20 houses considered to create PV self-consumption communities across the 12 European countries. The sample mean is represented by a red straight line with the standard deviation given by red dashed lines while the number of dwellings is given by the frequency.

2.4. Grid charges

To calculate grid charges and compare them across various European countries, we use input data from Eurostat, which is the official statistical office of the European Union. Energy storage technologies are considered as an electricity consumer during the charging cycle and as electricity generator during the discharge cycle. Eurostat publishes the network costs incurred by consumers depending on their size, in particular the load component, NC_L (€/kWh) which corresponds to the electricity charged into a storage plant (EUROSTAT, 2016b). The largest consumer for which network costs are given across all countries corresponds to 1500 GWh per annum, therefore we use these values as input data for PHES (see Table S16), although the annual charge of a 1 GW PHES plant is around one order of magnitude higher for any country (this can be derived from Fig. 4-b when multiplying the full load operating hours by the nominal capacity). This means that we may be overestimating grid charges for PHES, but we model them with the best open-source available data (EUROSTAT, 2016b). For community batteries, we refer to a consumer of less than 20 MWh per annum after analysing the optimised battery operation with the equivalent full cycles (EFC) in Fig. 5-b (the maximum battery charge of 19.6 MWh per annum corresponds to Italy).

Secondly, network charges are divided into two components, namely generation, $Gen_{\%}$, and load, $L_{\%}$, which are given in Table S17 and Table S18, for PHES and community batteries, respectively, following the data published by ENTSO-E. Finally, we break down grid charges into a capacity-based (power) component, $P_{\%}$, and volumetric-based (energy) component, $E_{\%}$, and model their share as 0.75 and 0.25 respectively, for both the charge (offtake) and discharge (injection) components, based on information shared by EASE (European Association for Storage of Energy (EASE), 2017). Therefore, for any country, the grid charges paid by energy storage can be determined with *Equation* 20, where the generator component, NC_{Gen}, i.e. the discharge, is given by *Equation* 21.

2.5. Benefit stacking

Here, we develop a data-driven methodology using the revenue of various storage applications already published in the previous literature, given in Table S19, to evaluate how the value created by energy storage increases when applications are combined. Since electricity prices and other input data, e.g., distribution network characteristics and frequency control prices, which are needed to model some storage applications such as distribution upgrade deferral and frequency control are not open source, we only computed benefit stacking for Switzerland, where data were available based on previous research. Importantly, our analysis considers existing technical constraints to combine applications, e.g., frequency markets are assumed to be exclusive (i.e., not combinable among them) (Kober et al., 2019) and PV self-consumption reduces the amount of demand to be shifted when a battery also performs demand load-shifting (Parra and Patel, 2019). Furthermore, we combine secondary frequency market with electricity arbitrage for bulk storage, considering it adds more value than primary and tertiary frequency control in Switzerland. The value of some applications, e.g., frequency control is given in power terms (€/MW) but we levelise it per electricity discharge (i.e. becoming €/MWh) based on the electricity discharge associated with the primary application (e.g., wholesale electricity arbitrage for bulk storage) to make results comparable. While the avoided cost of distribution grid reinforcements can be very high, distribution grid assets have a typical lifetime of 40 yr, which is substantially higher than a typical lifetime of a battery (15 yr are assumed in this study) (Gupta et al., 2021; Heptonstall and Gross, 2021). Thus, the battery value for this application has been levelised throughout the period of 40 yr. Finally, lithium-ion batteries with a round-trip efficiency of 86% are assumed for behind-the-meter, community and distributed storage while PHES with a round-trip efficiency of 80% is considered for bulk storage (see Table S15).

3. Results

3.1. Definition of storage

The first accomplishment of the 2019 E-Directive is to provide in article 2 (59) a long-awaited legal definition for energy storage, as highlighted by Gährs and Knoefel (2020). Energy storage is defined as: "deferring the final use of electricity to a moment later than when it was generated, or the conversion of electrical energy into a form of energy which can be stored, the storing of such energy, and the subsequent reconversion of such energy into electrical energy or use as another energy carrier". This definition locates energy storage as a specific step in the electricity chain, separated from the generation and consumption activities. This recognition is reinforced by article 1 of the 2019 E-Directive presenting its subject matter: establishing "common rules for the generation, transmission, distribution, energy storage and supply of electricity". The definition is technology neutral as it is compatible with the different energy storage principles, such as mechanical (e.g., PHES) and electrochemical (e.g., lithium-ion batteries), with this neutral approach being positive for industry (see experts' opinion regarding the new storage definition Table S6 of the SI). Importantly, sector coupling, e.g., power-to-gas and power-to-heat, is also acknowledged, and it can facilitate the decarbonisation of hard-to-abate sectors such as transport and industry. This technology-neutral approach should stimulate competition among storage technologies for various applications and scales, and thus trigger the provision of flexibility services at the highest efficiency and lowest cost as well as innovation (Gupta et al., 2020; Kober et al., 2019).

3.2. Ownership and operation rules

Ownership remains one of the critical questions for the development of energy storage, as shown by the different positions in the storage industry (see expert's views in Tables S7–S9). Fig. 3 below is a schematic representation of the various ownership models which are enabled by the 2019 E-Directive. First, the 2019 E-Directive states in articles 36 (1) and 54 (1) that network operators shall not own, develop, manage nor operate energy storage. Therefore, the new legal regime considers

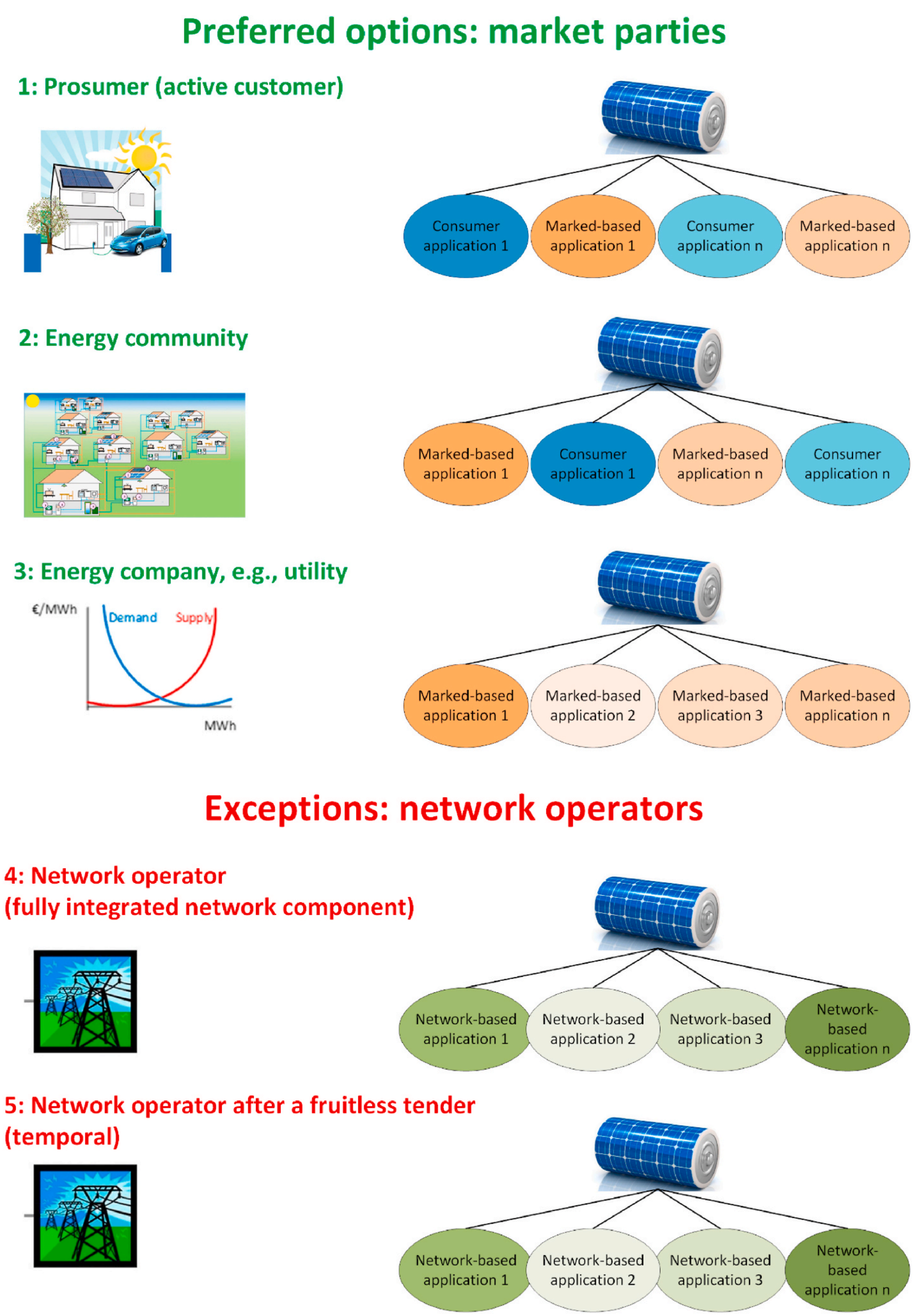

Fig. 3. Schematic representation of the ownership models enabled by the 2019 E-Directive. The bubbles with different colours on the right represent various generic storage applications which can be performed for various market parties and network operators. A classification of different storage applications is given in Table S19.

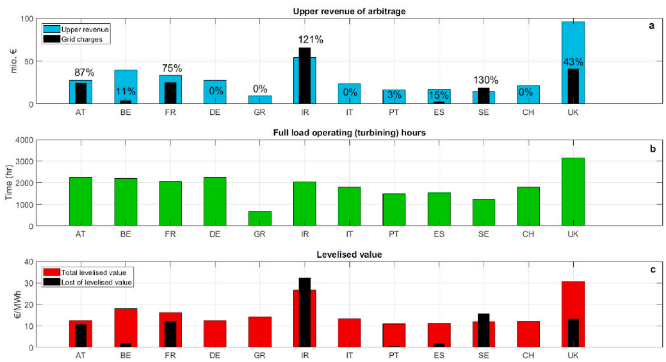

Fig. 4. Simulated results for a 1 GW PHES plant across 12 European countries: a) Upper boundary of revenue available for electricity arbitrage, indicative grid charges which would apply for its operation and the percentage between them; b) Number of full load operating hours based on the electricity discharge (turbine); and c) levelized value and loss of levelized value (i.e. levelized cost of grid charges) associated with the grid charges (percentages are not shown here but same values as in subplot a remain).

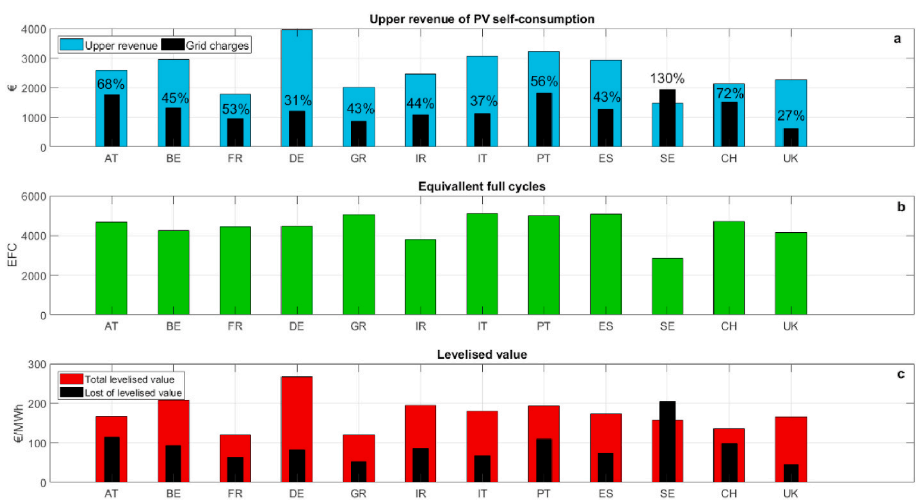

Fig. 5. Simulated results for a 50-kWh community battery performing PV self-consumption across 12 European countries: a) Upper boundary of revenue available, indicative grid charges which would apply for its operation and the percentage between them; b) Number of equivalent full cycles (EFC) assuming a lifetime of 15 years; and c) levelized value and loss of levelized value (i.e. levelized cost of grid charges) associated with the grid charges (percentages are not shown here but same values as in subplot a remain).

energy storage as a market activity. However, there are some exceptions to this regime as specified in articles 36 (2) and 54 (2).

The first exception in the 2019 E-Directive applies when storage plants can be considered as fully integrated network components. In this case, network operators can own or operate storage plants integrated to their system if they are "used for the sole purpose of ensuring a secure and reliable operation of the transmission or distribution system", and with the approval of the national regulatory authority (NRA). In any case, network operators are prohibited to use these fully integrated network components for balancing and congestion management (article 2 (51)).

The second exception applies when three conditions are met. Firstly, a tender must be organized under the supervision of a NRA to award the right to own and operate energy storage to market parties. However, this tender should result fruitless, i.e., there is not any interested market party, or they propose too costly and/or overlong services. Secondly, the application of energy storage is essential for the network operators' mission while not being used on electricity markets (which encompass energy, capacity, balancing and ancillary markets as detailed in article 2 (9)). And thirdly, the responsible NRA proceeds to an assessment of the tendering procedure and the need for derogation. In any case, according to articles 36 (3) and 54 (4), a public consultation must be organized at least every five years by the NRA to assess the interest of market actors to invest in energy storage to provide the required services in a cost-effective manner. If this is the case, network operators would have to phase out their storage activities within 18 months (importantly, this phase out does not apply to the first exception, namely fully integrated network components), and they may receive a reasonable compensation for their investments. We argue that the five-year reassessment may discourage network operators from investing in energy storage, even in the case of a fruitless tender in the first place, as the payback of a storage plant is typically longer (Parra and Patel, 2019; Ziegler et al., 2019; Stephan et al., 2016) and the potential compensation is unknown.

Therefore, network operators are forced to procure the storage services they need from market actors such as utility companies, active customers, energy communities and aggregators, which will have an important role to play in guaranteeing the system's balance. Interestingly, distribution system operators (DSOs) are now strongly incentivised to procure such services, according to article 32 (1) of the 2019 E-Directive. This is a change in comparison to the former legal regime where only TSOs were responsible for balancing and congestion management. Now, DSOs shall cooperate with TSOs for the effective participation of distribution-grid connected market participants willing to provide balancing services (article 31 (9)). In addition, congestion can now be managed at various voltage levels by both TSOs and DSOs, which raises questions of coordination. Hadush and Meeus argued that congestion should be solved at the border between the transmission and the distribution grid, at the border between the distribution grid and final consumers, or a combination of the two (Hadush and Meeus, 2018). In any case, TSOs and DSOs should share information about the activation of balancing capability between them to avoid problems such as double activation at the same time (European Network of Transmission System Operators for Electricity (ENTSO-E), 2017).

Among the various market parties who can provide flexibility to the energy system (see Fig. 3), prosumers[2] and energy communities are highlighted by the new legal framework. Prosumers refer to consumers who generate electricity within their premises and consume it, store it, sell it or participate in flexibility or energy efficiency schemes, provided that those activities do not constitute their primary commercial or professional activity. Prosumers can act collectively under conditions of proximity. Energy communities are another key novelty of the 2019 E– and 2018 RES-Directives (defined in articles 2 (11) and 2 (16), respectively), since they are entitled to engage into energy storage activities.

[2] The 2019 E-Directive and Regulation, as well as the 2018 RES-Directive respectively use the term 'active customer' (article 2 (8)) and 'renewables self-consumer' (article 2 (14) and (15)), instead of 'prosumer'.

Overall, energy communities are characterized by a regime that lies between traditional market parties (e.g., electricity generators, aggregators, etc.) and prosumers, as shown in Table 2.

3.3. Energy storage grid fees

In the 2019 E-Directive, the very term of “double charges” is only used once (article 15 (5) (b)) to protect prosumers from it. For other storage scales and applications (see Fig. 3), no such clear stance is taken. Instead, the 2019 E-Regulation states in article 18 (1) that “network charges shall not discriminate either positively or negatively against energy storage or aggregation, and shall not create disincentives for self-generation, self-consumption or for participation in demand response” (Regulation, 2019). This provision can be interpreted as a justification for applying network tariffs each time a storage technology uses the grid (to avoid a positive discrimination), or, conversely, as the end of double network charges. The prohibition of positive discriminations means that EU countries cannot simply relieve energy storage from their ‘fair share’ of network charges, even though it could be argued that energy storage provides flexibility to keep the grid stable (Gupta et al., 2021; Müller et al., 2017; Sakti et al., 2018b) (see experts view in Table S10). National legislatures and maybe the (national or EU) judicial power will, in the end, have to decide what a fair share means (see Tables S11–14 for experts’ considerations at the national level). For example, whether network charges are imposed on electricity extraction or injection impacts storage attractiveness for flexibility services provision since the second is lower due to storage losses. In Germany and Switzerland, it was decided in the last decade that only the electricity produced from renewable sources, stored by PHES and injected into the grid (i.e. after conversion losses) benefits from the renewables’ support scheme (Schreiber, 2020). Alternatively, network charges could be imposed on energy losses, to incentivise the deployment of the most efficient storage technologies. As quantified next, grid fees have a high impact on the profitability of energy storage.

Fig. 4 shows the upper revenue of a 1 GW PHES plant performing arbitrage in the day-ahead wholesale market together with the grid charges incurred by the operation depending on the country in 2016. It should be noted that 1 GW is completely hypothetical because the topography in some countries, e.g., Ireland and Belgium, does not allow to reach it. We notice that both the upper revenue and grid charges for PHES varied markedly (up to one order of magnitude) across European countries, ranging from €9.5–95.9 M per annum and €0–65.6 M per annum, respectively. Some countries such as Germany, Greece, Italy, Portugal and Switzerland promote PHES operation by eliminating any grid charge, which made the net revenue equal to the upper revenue, e.g., €30.0 M, €23.6 M and €21.5 M per annum for Germany (2260 h of full load operation), Italy (1777 h) and Switzerland (1795 h), respectively. On the other hand, grid charges markedly reduced the economic attractiveness of PHES in Austria, France, Sweden, and the UK, representing 86.7%, 74.8%, 130.4% and 42.9% of the upper revenue, respectively. The most extreme case is Ireland, where a PHES plant would have lost money when performing arbitrage as a single application. Only in the UK, the net revenue (€54.8 M per annum) was still attractive since it was the country where PHES operated with more full load hours (3143 h) thanks to a relatively high standard deviation in wholesale electricity prices (see Fig. 1 and Fig. S1). Finally, we further notice the limited levelised value provided by electricity arbitrage in wholesale electricity markets, ranging between 10.9-30.5 €/MWh without the consideration of grid charges, resulting from the increasing share of solar and wind power across several markets, as well as relatively low oil prices, which has been largely debated in the previous literature (Soini et al., 2019; Sensfuβ et al., 2008).

In a second step, we determine grid charges and how they compare with the upper revenue of a hypothetical 50-kWh community battery performing PV self-consumption for 20 houses across the same European countries in Fig. 5. Increasing local PV self-consumption adds significant value, up to a levelized value of 266.3 €/MWh (equivalent to 3775.4 € per annum) for Germany[3] which has very high retail electricity prices (see Table 1), compared to the value created by electricity arbitrage, with a maximum of 30.5 €/MWh for the UK. However, front-of-the-meter community storage is not exempted yet from grid fees across any European country, finally amounting between 26.8-130.0% of the generated revenue depending on the country. Therefore, the extra value of PV self-consumption is offset by the higher grid charges. If we compare grid fees incurred by a community battery and a PHES plant, we notice that, first, grid fees range between 44.2-203.1 €/MWh and 0–32.3 €/MWh, respectively, i.e. they are markedly higher for community storage in absolute terms, despite the higher round trip efficiency of batteries (86%) compared to PHES (80%) as indicated in Table S16. Yet, the relative impact of grid fees on the revenue is markedly higher for PHES than for community batteries in countries where PHES does not enjoy any exemption from grid fees, such as the UK (42.9%) and Ireland (121.3%), due to the lower value offered by electricity arbitrage.

3.4. Benefit stacking

To the best of our knowledge, there is not any clear regime authorizing benefit stacking in the EU yet (CMS, 2018). However, the UK, now a former EU country, rolled out since October 2020 a new balancing market that allows benefit stacking and proved successful for (large) batteries. Nonetheless, this is not to be taken as a comprehensive legal regime yet (Mauger and Roggenkamp, 2022). Interestingly, California adopted for this purpose a set of rules in 2018, referred to as Multiple Use Application of storage (California Public Utilities Commission (CPUC), 2018). California is an interesting benchmark to be compared with the EU, given that a degree of network operation unbundling is required in both cases. First, the California Public Utilities Commission (CPUC) distinguishes between reliability and non-reliability services that can be provided to grid operators and users, respectively. Secondly, the CPUC established 11 rules for energy storage procurement, contracts, and evaluation protocols. In a nutshell, energy storage can only deliver applications to its connection level, and to a higher level, but not downstream (except for community storage). Furthermore, applications which ensure the reliability of the power system have priority. Several of the rules aim at ensuring that storage operators have the capacity to fulfil their commitment to sell multiple flexibility services (Fullbright). Otherwise, operational incompatibilities would be detrimental to the overall grid stability. Such type of legal regime should be adopted in the EU to facilitate benefit stacking, given the increase in the value of energy storage, as illustrated in Fig. 6.

Fig. 6 shows the results of performing benefit stacking depending on the deployment scale, namely behind-the-meter (and community), distributed and bulk, with the value of individual applications given in Table S19 of the SI. We consider a primary application for each type of scale, namely PV self-consumption, wholesale electricity arbitrage and deferral of distribution grid reinforcement for behind-the-meter (and community), bulk and distributed storage, respectively, to analyse the extra upper revenue associated with the combination of applications, and we exclude the role of aggregator to better delimit each type of scale. We notice that benefit stacking increases markedly the upper revenue of energy storage for behind-the-meter and community storage, since their value increases by around 160% (up to 303 €/MWh) relative to the primary application (PV self-consumption). For these two scales, nearly all applications (e.g., demand peak-shaving with a levelized value of 145 €/MWh) offer a relatively high revenue when performed as single applications. However, the stacked value is lower for distribution network applications, and is mainly driven by deferral of distribution

[3] The upper value of community storage is equal to the net value of behind-the-meter storage owned by prosumers since it is exempted from grid charges.

Table 2
Comparison between legal provisions in EU law concerning energy storage owned by prosumers, namely active customers and renewables self-consumers, and energy communities, namely citizen energy communities and renewable energy communities.

Market party	Legal name	Directive	Storage ownership and management	Authorisation for benefit stacking
Prosumer	**Active customer (AC)**	2019 E-Directive	Yes (within their premises)	Yes (art. 15 (5) (d))
	Renewables self-consumer (RSC)	2018 RES-Directive	Yes (within their premises)	Unspecified
Energy community	**Citizen energy community**	2019 E-Directive	Yes	Unspecified
	Renewable energy community	2018 RES-Directive	Yes	Unspecified

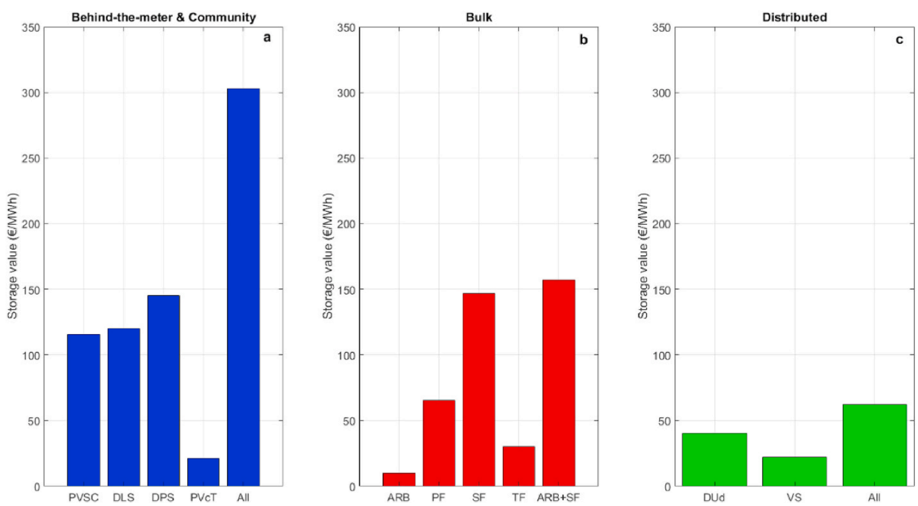

Fig. 6. Upper levelised value (i.e. revenue) created by individual applications and their combination, i.e. benefit stacking, depending on the deployment scale in Switzerland. Batteries are assumed for behind-the-meter (and community) and distributed storage, while a PHES is assumed for bulk storage. PVSC stands for PV self-consumption; DLS stands for demand load shifting; DPS stands for demand peak-shaving; PVcT stands for avoidance of PV curtailment; ARB stands for electricity arbitrage; PF stands for primary frequency control; SF stands for secondary frequency control; TF stands for tertiary frequency control; Dud stands for distribution upgrade deferral; and VS stands for voltage support.

grid reinforcement equal to 40.4 €/MWh (Gupta et al., 2021) (based on a distribution grid of a specific DSO in Switzerland and therefore should not be generalised to other distribution grids). Likewise, the combination of applications makes bulk storage markedly more attractive, up to 157.1 €/MWh for the combination of electricity arbitrage and secondary frequency control, offering an intermediate value between behind-the-meter/community storage and storage for distribution network applications. Although the final value created by energy storage applications such as deferring grid upgrades and delivering ancillary services such as voltage support is region-specific based on demand, supply and network characteristics, the Swiss case illustrates that benefit stacking is a key strategy to increase the value and profitability of storage investments, potentially helping them to reach the break-event point. Our results positively align with other studies reported in the literature, e.g., Englberger et al. stated that benefit stacking improves the annual profitability by 63–124% (Baumgarte et al., 2020), and Battke et al. who modelled an increase of almost 1 in the net present value per unit of capital expenditure (Stephan et al., 2016).

4. Conclusions and policy implications

In Europe, the 2019 E-Directive acknowledges the importance of energy storage by providing an enabling framework with fair treatment as well as a level playing field. Based on our interdisciplinary legal and techno-economic analysis including semi-structured interviews with experts in the energy industry, we have studied four key regulatory barriers, with their interlinkages explained in Table 3.

Here, we discuss four key implications of the new regime, for the energy storage industry, policymakers, and academics. Firstly, the new legal regime defines energy storage and differentiates it from energy generation and consumption. This definition is a prominent addition by the new regime, since it is technology-neutral and broad, also including sector coupling with gases (e.g., hydrogen) and heat. It implies that all technologies should be treated equally by policymakers, and it is the role of market-parties to make the optimal choice based on their applications.

Secondly, the 2019 E-Directive tackles the deep uncertainty linked to ownership and operation of energy storage. It prohibits energy storage ownership and operation by network operators, namely TSOs and DSOs, despite the previous interest in storage shown by some of them as discussed during the expert interviews (see Tables S7–S9). However, the 2019 E-Directive allows for two exceptions to this rule: energy storage as a fully integrated network component, and after a fruitless tender. Co-ownership and operation of such facilities by network operators and market parties in the context of R&D projects could be interesting to showcase the value of storage for grid networks. In any case, the transposition of the new regime in national legislations should still impact the future ownership rules, e.g., the openness of national energy regulators to network operators' ownership of energy storage after a fruitless tender.

Thirdly, our findings show that benefit stacking does not benefit from a legal framework in the EU, albeit it is a key strategy to significantly increase the value of energy storage. This is the case for behind-the-meter and community storage with a value increase of, at least, 162%, which could be boosted further by accessing ancillary markets using an aggregator as an enabler. As a result, behind-the-meter and community storage can provide a twofold higher value (relative to the annual discharge) than bulk energy storage and energy storage owned by network operators. Thus, benefit stacking should be used by market-parties, from prosumers to utility companies, to reduce the payback time of energy storage. At the same time, network operators should provide transparent information to market parties about their flexibility needs in advance (as they are incentivised to do in the 2019 E-Directive) as well as developing customised technical controls and legal contracts. In addition, relevant EU network codes such as the Electricity balancing guideline need to be updated to authorise such activities (Commission Regulation, 2017), and the results of the process of creation of a new network code on demand side flexibility should be scrutinised (ACER, 2021). Here, we finally argue that future policies should facilitate the aggregation of behind-the-meter and community storage assets, and

Table 3
Interconnections among the four key regulatory barriers analysed in this study.

	Definition	Ownership	Grid charges	Benefit stacking
Definition	n.a.	Technology-neutral definition stimulates competition for each ownership model	While the new definition is technology-neutral, grid charges are not	The new technology-neutral energy storage definition does not prohibit benefit stacking, allows flexible technologies to stand out when combining applications.
Ownership	Technology-neutral definition stimulates competition for each ownership model	n.a.	Ownership models are subject to different grid charges, e.g., prosumer (active customers) versus energy communities	Benefit stacking may be more challenging after the prohibition for network operators to own storage
Grid charges	While the new definition is technology-neutral, grid charges are not	Ownership models are subject to different grid charges, e.g., prosumer (active customers) versus energy communities	n.a.	Grid charges have a strong impact on the profitability of storage and benefit-stacking can help overcome this issue
Benefit stacking	The new technology-neutral energy storage definition does not prohibit benefit stacking, allows flexible technologies to stand out when combining applications.	Benefit stacking may be more challenging after the prohibition for network operators to own storage	Grid charges have a strong impact on the profitability of storage and benefit-stacking can help overcome this issue	n.a.

their access to flexibility markets, since this action can reduce, or even eliminate the need for subsidies, tax incentives and other forms of support (Zame et al., 2018; Faunce et al., 2018; Lai and Locatelli, 2021).

A fourth and key implication of our analysis results from our comparison of various deployment scales for energy storage in the context of the new legal framework. We foresee a widespread adoption of behind-the-meter batteries across most EU countries considering: (i) the prohibition of double charges for flexibility provided by prosumers according to the 2019 E-Directive; (ii) forecasted technological trends on battery cost reduction (Schmidt et al., 2017); and (iii) the capital cost of batteries scales down remarkably like PV (this is not, for example, the case for technologies such as wind (IRENA, 2019) and hydrogen (Parra and Patel, 2016) which, on the other hand, offer greater economies of scale). Besides, community energy storage may become a central element of energy communities, if it is exempted from double charges, or at least, grid charges become more progressive and granular, stimulating the integration of community flexibility. This addition would unlock the community-based flexibility potential to transform the energy system, also considering that community energy represents an attractive scale to engage citizens and accelerate the reduction of carbon dioxide emissions (Devine-Wright, 2019; Koirala et al., 2016). Some advantages of community energy storage include a better balancing of PV supply and local demand than bulk storage systems, while the community scale is also more efficient and cost-effective than household storage (Parra et al., 2017; Barbour et al., 2018). The 2019 E-Directive hedges community storage against unfair double charges but the details of the transposition of the new regime in national legislations will be key for the final attractiveness of community storage. If double-charges are maintained in national legislation, community energy storage may be limited to blocks of flats, i.e. a shared behind-the-meter solution, and the potential flexibility services to be provided to the grid would be significantly reduced. While our analysis is based on self-consumption communities, this conclusion also holds for other schemes such as peer-to-peer communities, since batteries interact more with the main grid (i.e. perform more cycles) when embedded in peer-to-peer communities than in self-consumption communities (Peña-Bello et al.). This outcome underlines the critical importance that double charges have on the development of energy storage. The legal framework will therefore impact the final share of behind-the-meter and community storage, which outcome will bring new opportunities for aggregators to manage this potentially massive, distributed storage capacity and flexibility.

To conclude, this paper is the first to show quantitatively and across various European countries the impact of the new energy storage legal framework on the value of storage for all relevant scales, combining information from techno-economic modelling, legal analysis, and expert interviews. However, our study is not without limitations, which in turn call for future research. We propose four topics. First, benefit stacking is analysed for Switzerland and comparing with other geographies would be helpful to confirm whether the associated application revenues are geographically dependant. Secondly, this analysis could be enriched with the details of the national transpositions of the new regime when they become available, e.g., national grid fees for community energy storage as well as exceptions for storage ownership by network operators. Thirdly, the analysis could be extended to other geographies with different renewable resources, demand profiles and regulatory contexts. Finally, the impact of market coupling across the EU and its expected positive impact on electricity prices and congestion issues could further be linked with the value of energy storage.

Author contributions

David Parra: Conceptualisation, Modelling and simulation, Validation, Formal analysis, Investigation, Writing, Original Draft, Funding acquisition. Romain Mauger: Conceptualisation, Investigation, Writing, Original Draft. All authors gave their final approval for publication.

Declaration of competing interest

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

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Appendix A. Supplementary data

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