Utilities Policy 95 (2025) 101937

Contents lists available at ScienceDirect

Utilities Policy

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

Full-length article

Locating large-scale energy storage: spillover effects, carbon emissions, and balancing costs across Italy

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ARTICLE INFO

Handling editor: Janice A. Beecher

Keywords:
Energy storage
Carbon emission
Italy
Ancillary services
Day-ahead market

ABSTRACT

Reaching net zero requires substantial large-scale energy storage systems (LESS) deployment. This strategy poses key challenges, including understanding how different LESS technologies compare in terms of both economic benefits and environmental impact, as well as analysing the complex interactions within and between markets when storage is deployed. To help shed light on these aspects, we investigate how LESS location, rated power, duration, and technology can affect welfare and carbon emissions in the Italian electricity system by modelling the day-ahead and the ancillary services markets. We considered lithium-ion batteries, pumped-storage hydro, and vanadium redox flow batteries. The results show that deploying LESS is always beneficial in the day-ahead market, but ancillary services costs can increase due to spillover effects because these markets run sequentially. Lithium-ion is the technology that yields the best social welfare increase. Location, rated power, and duration significantly impact carbon emissions, with changes ranging from −260 kgCO2 to 190 kgCO2 per MWh traded. These results suggest that LESS can help increase welfare and induce unintended consequences, such as spillovers across markets with a mixed effect on emissions.

1. Introduction

Large-scale energy storage systems (LESS) are critical for decarbonising electricity grids and supporting the integration of intermittent renewable energy sources. Indeed, it is projected that global LESS deployment needs to reach 1.5–2.5 TW and 85–140 TWh by 2040, requiring investments of up to $3 trillion (Sánchez-Pérez et al., 2022). However, the increasing presence of LESS also raises new questions. For example, will the operation of energy storage align with environmental goals? Indeed, LESS deployment can have complex and sometimes unexpected effects on carbon emissions and market dynamics. For instance, wholesale arbitrage by storage owners may increase emissions by shifting the generation mix toward carbon-intensive energy sources (Beuse et al., 2021), with round-trip efficiency losses potentially exacerbating this effect.[1] Consequently, it is important to investigate how the substantial deployment of LESS required to reach net zero can affect energy markets and how this can influence social welfare[2] and carbon emissions.

This paper aims to help inform policymakers on how LESS's technology type, rated power, duration,[3] and location can affect welfare and carbon emissions, focusing on the Italian electricity system. In detail, we will compare a base case without LESS with several test cases obtained

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[1] For example, assume a storage with a round-trip efficiency equal to 0.80. To discharge 100 MWh, it requires 100/0.80 = 125 MWh as input. Assume a constant marginal carbon intensity at charging time equal to, e.g., 200 kgCO2/MWh; this totals 125 * 200 = 25,000 kgCO2. This means that the storage will reduce the overall carbon emissions only if the carbon intensity of the marginal unit it displaces at discharging time is greater than 250 kgCO2/MWh (i.e. 1/0.80 of the carbon intensity at charging time).

[2] Social (or economic) welfare is formally defined as the sum of the consumers' and producers' surplus, net of investment costs (Mankiw, 2011). The consumer surplus is the benefit obtained by consumers from purchasing a product at a price that is less than the maximum price that they would be willing to pay. Similarly, the producer surplus is the amount that producers gain by being able to sell at a market price that is more than the minimum price they would be willing to sell. Therefore, social welfare is a measure of the well-being of all actors participating in a market net of investment costs. In this work, we will also use the term market surplus to focus on the welfare of a specific market without accounting for investment costs.

[3] The duration is defined as the ratio of rated energy to rated power.

https://doi.org/10.1016/j.jup.2025.101937
Received 19 September 2024; Received in revised form 29 March 2025; Accepted 29 March 2025

by placing LESS in different locations of the Italian transmission network. We will consider the two main Italian electricity markets, viz. (i) the Italian day-ahead, which is a zonal market subject to the Unique National Price (PUN) rule (see Section 3.1), where the bulk of the electricity is traded, and (ii) the ancillary services market, which is used by the transmission system operator (TSO) to manage network congestion, procure reserve, and offset energy imbalances. To properly simulate the functioning of the ancillary services market, a high-fidelity model of the Italian transmission network (detailed in Section 3.3) has been developed. We tested three LESS technologies: lithium-ion batteries, pumped-storage hydropower, and vanadium redox flow batteries, with different combinations of rated power and duration. These technologies have been selected as they currently are some of the most mature for grid-scale usage, given the daily time horizon of the considered markets (Hunter et al., 2021).

The main results of this work highlight that deploying LESS in the Italian electricity system may have a mixed effect on carbon emissions, which may decrease or increase depending on the LESS location, rated power and duration. In particular, we observed a non-negligible spillover effect (see Section 5.1) between day-ahead and ancillary services markets caused by the presence of LESS, which can increase balancing costs. These findings and contributions can be of interest to (i) regulators and policymakers by informing them on how the presence of LESS can affect the decarbonisation of the energy system, providing insight that may help shape the current EU regulatory framework on energy storage (Directorate-General for Energy EU, 2023); (ii) energy economics academics who want to understand the modelling aspects of the Italian electricity markets, which are characterised by peculiar features, such as the PUN (see Section 3.1), and (iii) LESS investors and operators interested in understanding the techno-economic case for storage technologies.

To summarise, the main novelties of this work are:

- Analysing how LESS can affect social welfare and carbon emissions in the Italian electricity system, focusing on different technologies, locations, rated power, and durations.
- Developing a high-fidelity Italian transmission network (consisting of more than 1800 nodes), which has been used to simulate the functioning of the ancillary services market.
- Demonstrating that deploying LESS in the Italian electricity system can have mixed effects on carbon emissions, decreasing or increasing emissions depending on the storage location, rated power, and duration.
- Providing insights for regulators and policymakers on how storage affects the energy system, including identifying significant spillover effects between day-ahead and ancillary services markets.

2. Literature review

In the literature, a comprehensive analysis of the effect of introducing LESS in European countries was reported by Beuse et al. (2021). Using 2018 data, they analysed seven nations: Italy, Germany, France, Great Britain, Spain, Poland, and Greece. However, they assumed inelastic demand and ignored network constraints—countries were modelled as single zone markets, and energy storage was assumed to be a price taker, i.e., LESS deployment could not affect market prices. The results show that storage devices can have a non-negligible effect on carbon emissions; these can either increase or decrease depending on the market and country. In particular, the change in carbon emissions caused by LESS can range from negative 250 kgCO2 per MWh discharged in countries like France to positive 500 kgCO2/MWh in coal-dependent countries like Poland. For Italy, their results highlight a mixed effect, with emissions ranging between negative 250 kgCO2/MWh to positive 250 kgCO2/MWh depending on the storage operation and market. Beltrami (2024) examines the average environmental benefit associated with hydroelectric storage (pumped-storage hydro and programmable hydroelectric power plants) in Northern Italy's power market zone by building upon the concept of marginal emission factor, which represents the marginal CO2 effect resulting from a 1 MWh increase in hydrostorage generation. The results, based on ordinary-least square estimation using 2018 data, show that hydroelectric storage can reduce carbon emissions in aggregate terms, with an estimated marginal emission factor equal to -0.13 *t*CO2/MWh, which reaches -0.17 *t*CO2/MWh during off-peak periods, thus revealing the potential for carbon displacement, particularly during low-demand periods.

Khalilpour et al. (2017) analysed the effect of deploying lithium-ion batteries with 1-h duration and 1.5 GW of total power in the Australian national electricity market. Their results show that introducing these assets can decrease the total carbon emission by up to ~0.65 % compared to the case without storage, thanks to increased flexibility and reduced wind curtailment. The presence of LESS also contributes to reducing overall costs by ~1 %, decreasing the average short-run marginal cost.

Several authors investigated the effect of LESS on the US energy system. Cavicchi and Ross (2020) reported the effect of deploying LESS in the New England energy system in a high wind penetration scenario, showing that the deployment of 9 GW of wind power with a 30 % load factor, coupled with 10 GW of energy storage with a 4-h duration, can reduce carbon emissions by up to 50 %. However, conventional gas-fired power plants would still be required, and the cost of a further reduction of carbon emissions through additional storage capacity could reach $1350 per tCO2. A broader study on the US energy system by Babacan et al. (2018), which focuses on providing energy storage by aggregating home batteries, shows that carbon emissions can significantly increase if households operate storage to minimise their electricity bill. Thus, decentralising energy storage might not necessarily help decarbonise the energy system. By contrast, when operating to minimise emissions, they can reduce average household emissions by 2.2–6.4 %, but this involves a cost ranging from $180 to $5160 per tCO2 avoided. Fares and Webber (2017) report similar findings, showing that the usage of energy storage by households to capture solar energy can increase emissions by up to 303 kgCO2 per household in Texas annually. Arbabzadeh et al. (2019) discuss the role of LESS under a scenario of high-penetration of renewable energy using the Texas and California power systems as test cases. They examined nine storage technologies, including pumped-storage hydro, vanadium-redox, and lithium-ion. Their results show that LESS can help reduce carbon emissions, and pumped-storage hydropower appears to be the most beneficial technology.

Pimm et al. (2019, 2020) investigated the marginal emission factor in Great Britain, showing that the impact of energy storage can significantly change with location and operation mode. The greatest emissions reduction can be achieved when LESS help reduce wind curtailment in areas with high levels of fossil fuel generation. By contrast, emissions can increase when energy storage offsets power imbalances with minimal wind curtailment. The difference between the two cases can be more than 700 kgCO2 per MWh.

With respect to social welfare, Sidhu et al. (2018) discuss the results of the Smarter Network Storage trial, which was the first commercial grid-scale battery in Great Britain and involved a 6 MW/10 MWh lithium-ion battery. They considered the provision of services, including frequency response, wholesale arbitrage, distribution network upgrade deferral, and security of supply, and estimated that social benefits could outweigh investment costs by more than 20 % at 2017 prices. Yagi and Takeuchi (2023) discuss the usage of pumped-storage hydropower in the Japanese energy system to deal with the variability of renewable power. Their results show that the benefit of avoiding curtailment can reach 2 million dollars for a 10 MW scale plant, i.e. ~10 % of its construction cost. In addition to an overall change in social welfare, the deployment of LESS can also induce a shift in surplus between investors, as Goteti et al. (2021) reported. They show that current marginal units, mainly gas turbines, can lose most of their operating income because they can

Fig. 1. The seven PUN zones of the Italian day-ahead market.

Fig. 2. The Italian high-voltage transmission network.

Table 1
Relationship between the day-ahead market zones and the Italian regions.

Zones	Italian regions
North	Val D'Aosta, Piedmont, Liguria, Lombardy, Trentino, Veneto, Friuli Venezia Giulia, Emilia Romagna
Centre North	Tuscany, Marche
Centre South	Lazio, Abruzzo, Campania, Umbria
South	Molise, Puglia, Basilicata
Calabria	Calabria
Sicily	Sicily
Sardinia	Sardinia

Table 2
Combination of rated power and duration for each technology used in the test cases.

Technology	Rated Power (MW)	Duration (h)
Lithium-ion	100	2
Lithium-ion	100	4
Lithium-ion	1,000	2
Vanadium Redox Flow	100	2
Vanadium Redox Flow	100	4
Vanadium Redox Flow	1,000	2
Pumped-storage Hydro	100	4

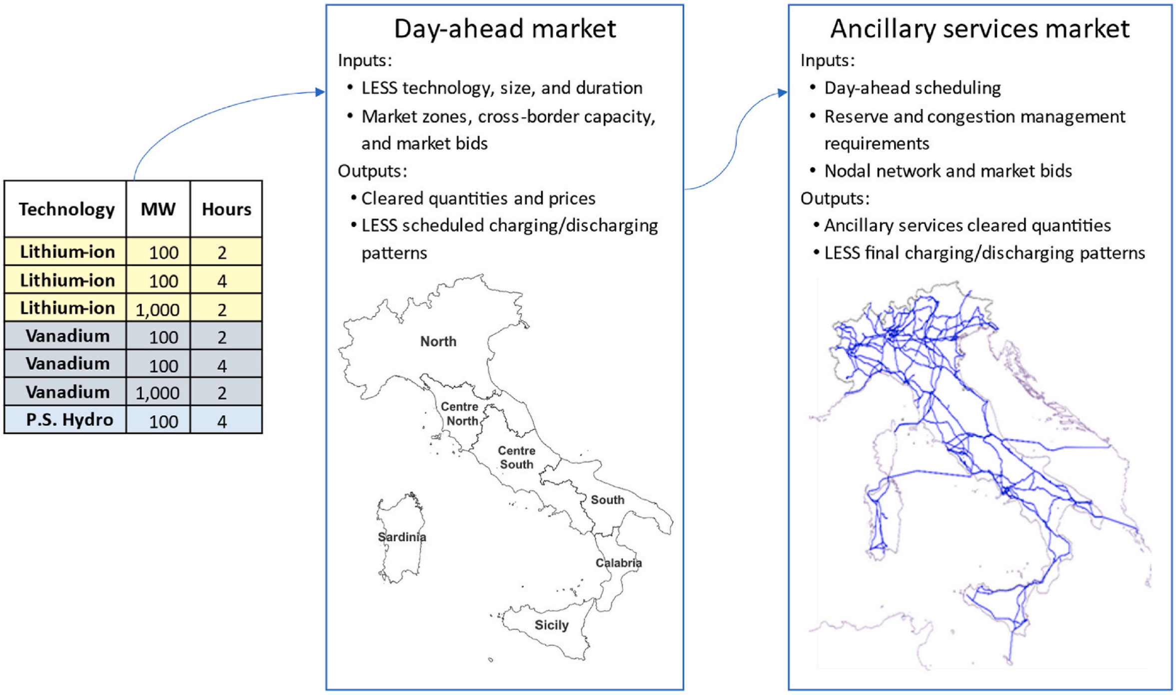
be displaced by energy storage and may be forced to retire in the long term. Giulietti et al. (2018) discuss arbitrage in the day-ahead market in the UK and argue that additional incentives are needed to make storage investment more attractive. Qin et al. (2023) developed an agent-based model to investigate the impact of different market participation options on storage's contribution to reducing electricity costs and carbon emissions in North America. Their findings suggest that the existing electricity pool market design may encourage early-stage storage adoptions but hinder progress toward deep decarbonisation, with day-ahead markets being more effective in utilising storage to reduce carbon emissions, while real-time markets are more effective in reducing costs. Kang (2022) discusses the importance of long-duration electricity storage technology in power systems with high penetration of renewable energy sources to facilitate a cost-effective transition to a low-carbon energy system, showing that long-duration storage is important for facilitating a cost-effective transition to a low-carbon energy system. Finally, a comprehensive review of energy storage systems and their applications in deregulated power systems, focusing on optimising system performance through the placement of LEES and renewable energy sources, is reported in Chakraborty et al. (2022).

3. Modelling Italian electricity markets

This section describes the functioning and modelling of the Italian day-ahead and ancillary services markets, as well as the high-fidelity transmission network of the Italian electricity system that has been developed. A Glossary is available in Appendix B.

3.1. The Italian day-ahead market

The Italian day-ahead market, also termed "Mercato del Giorno Prima" (MGP), is a zonal market consisting of seven physical zones, depicted in Fig. 1. This market is coupled with the rest of European day-ahead markets: a single European algorithm clears offers, implicitly allocating cross-zonal capacities, defining prices and accepted offers. The transmission system operator defines the borders between the zones, which are periodically revised to represent the main network congestion sources in a process called Bidding Zone Review (EntsoE, 2023a). The distinctive characteristic of the Italian day-ahead market is that generation, demand from pumping units and import/export are cleared at their zonal prices. By contrast, all demand orders from consumers in the Italian physical zones in Fig. 1 are cleared at the same price, termed Unique National Price, or PUN (Savelli et al., 2018). Formally, the PUN_t at time t is defined as the average of the zonal prices $\pi_{t,n}$ in each of the seven PUN zones $n \in N$, weighted by the consumers'



Technology	MW	Hours
Lithium-ion	100	2
Lithium-ion	100	4
Lithium-ion	1,000	2
Vanadium	100	2
Vanadium	100	4
Vanadium	1,000	2
P.S. Hydro	100	4

Day-ahead market

Inputs:
- LESS technology, size, and duration
- Market zones, cross-border capacity, and market bids

Outputs:
- Cleared quantities and prices
- LESS scheduled charging/discharging patterns

Ancillary services market

Inputs:
- Day-ahead scheduling
- Reserve and congestion management requirements
- Nodal network and market bids

Outputs:
- Ancillary services cleared quantities
- LESS final charging/discharging patterns

Fig. 3. The figure graphically represents the procedure used in each test case, where one LESS type is selected and placed in one market zone of the day-ahead market. Then, given the day-ahead scheduling, the ancillary services market is run to procure reserve and solve network congestions, obtaining the final LESS charging and discharging patterns.

Table 3
Cost parameters for the energy storage technologies used in the test cases. The economic life (years to pay off assets) has been assumed to be equal to the operation life, with a cap equal to 30 years for pumped-storage hydro. Note that operational and economic life account for augmentations and replacements to preserve the operational capability throughout the project. For example, for lithium batteries, this means replacing part of the rack approximately every 6 years (Viswanathan et al., 2022).

Parameters	Unit of Measure	Lithium	Lithium	Lithium	Vanadium Redox	Vanadium Redox	Vanadium Redox	Pumped-storage Hydro
Capex	$\$/\text{kWh}_{\text{cap}}$	427.18	385.21	399.72	708.15	505.88	672.27	511.00
O&M	$\$/\text{kW}_{\text{cap}}\text{-y}$	2.56	4.27	2.37	4.44	6.16	4.24	28.10
End-of-life costs	$\$/\text{kWh}_{\text{cap}}$	2.65	2.65	2.65	48.64	33.94	46.10	-
Round-trip eff.	%	83%	83%	83%	65%	65%	65%	80%
Construct. time	Y	1	1	1	1	1	1	5
Oper. life (+augm.)	Y	20	20	20	24	24	24	60
Econ. life (+augm.)	Y	20	20	20	24	24	24	30
Rated Power	MW_{cap}	100	100	1,000	100	100	1,000	100
Duration	h	2	4	2	2	4	2	4

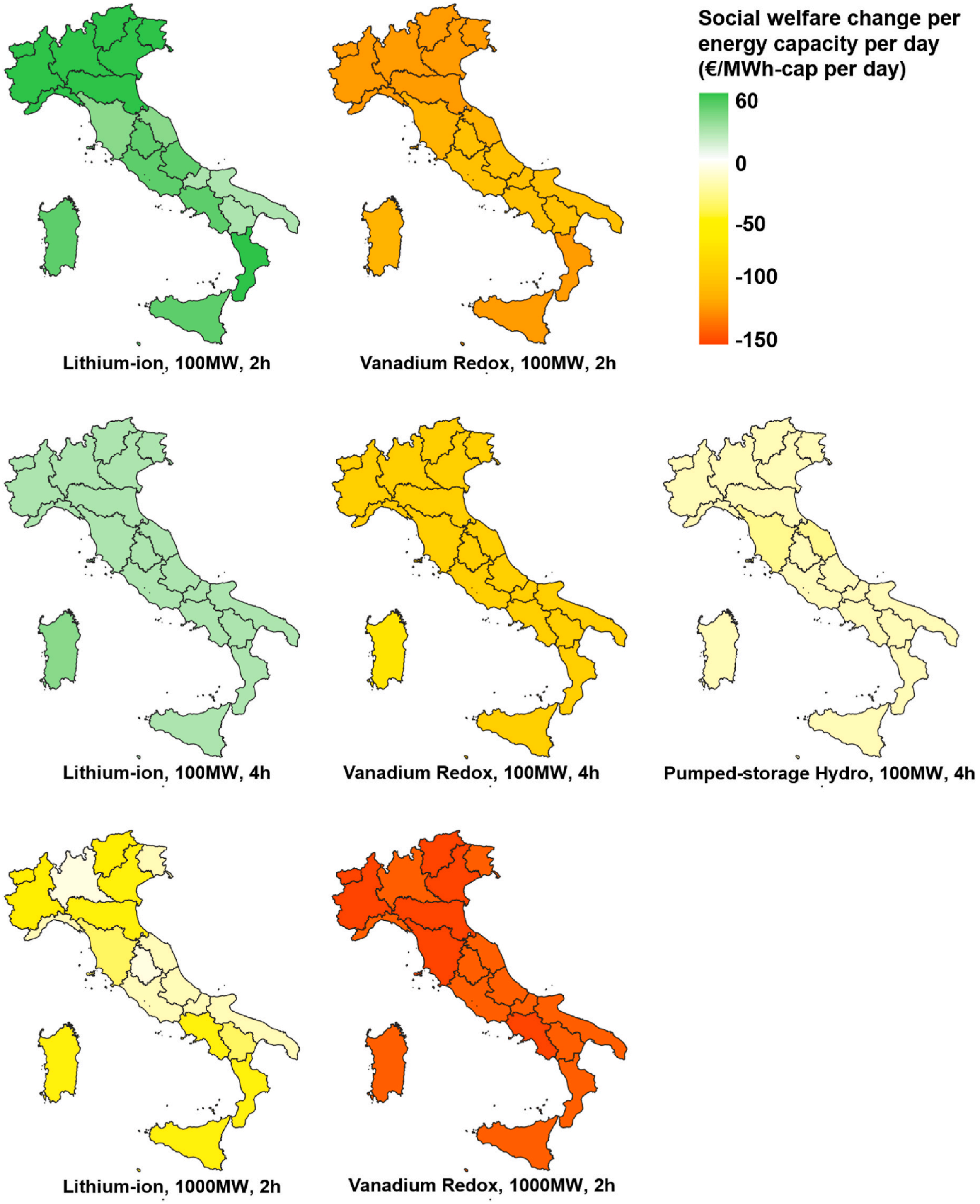
Table 4
Equivalent hourly costs for the considered storage technologies.

Technology	Rated Power (MW)	Duration (h)	Equiv. hourly cost c_k (EUR/h)
Lithium-ion	100	2	869
Lithium-ion	100	4	1,563
Lithium-ion	1,000	2	8,127
Vanadium Redox Flow	100	2	1,345
Vanadium Redox Flow	100	4	1,919
Vanadium Redox Flow	1,000	2	12,772
Pumped-storage Hydro	100	4	1,954

demand $D_{t,n}$, that is:

$$\mathrm{PUN}_t = \frac{\sum\limits_{n\in N} D_{t,n}\pi_{t,n}}{\sum\limits_{n\in N} D_{t,n}} \tag{1}$$

The definition in Equation (1) has three main consequences. First, it ensures that the total monetary amount collected from consumers is the same as if they had paid the zonal price instead. Indeed, rearranging the PUN definition, we have: $\mathrm{PUN}_t\sum_{n\in N}D_{t,n} = \sum_{n\in N}D_{t,n}\pi_{t,n}$. This approach ensures that the amount collected by the market operator from consumers can always cover the revenues paid to generators (who receive zonal prices) as in any optimal dispatch (Wu et al., 1996). Second, it creates an implicit subsidy among Italian consumers, as those in zones with low zonal prices end up paying a higher electricity price (i.e., the



Lithium-ion, 100MW, 2h

Vanadium Redox, 100MW, 2h

Lithium-ion, 100MW, 4h

Vanadium Redox, 100MW, 4h

Pumped-storage Hydro, 100MW, 4h

Lithium-ion, 1000MW, 2h

Vanadium Redox, 1000MW, 2h

Fig. 4. Social welfare change due to the LESS introduction in the Italian day-ahead and ancillary services markets, considering storage costs. The values are reported regarding daily benefit per MWh of installed energy capacity.

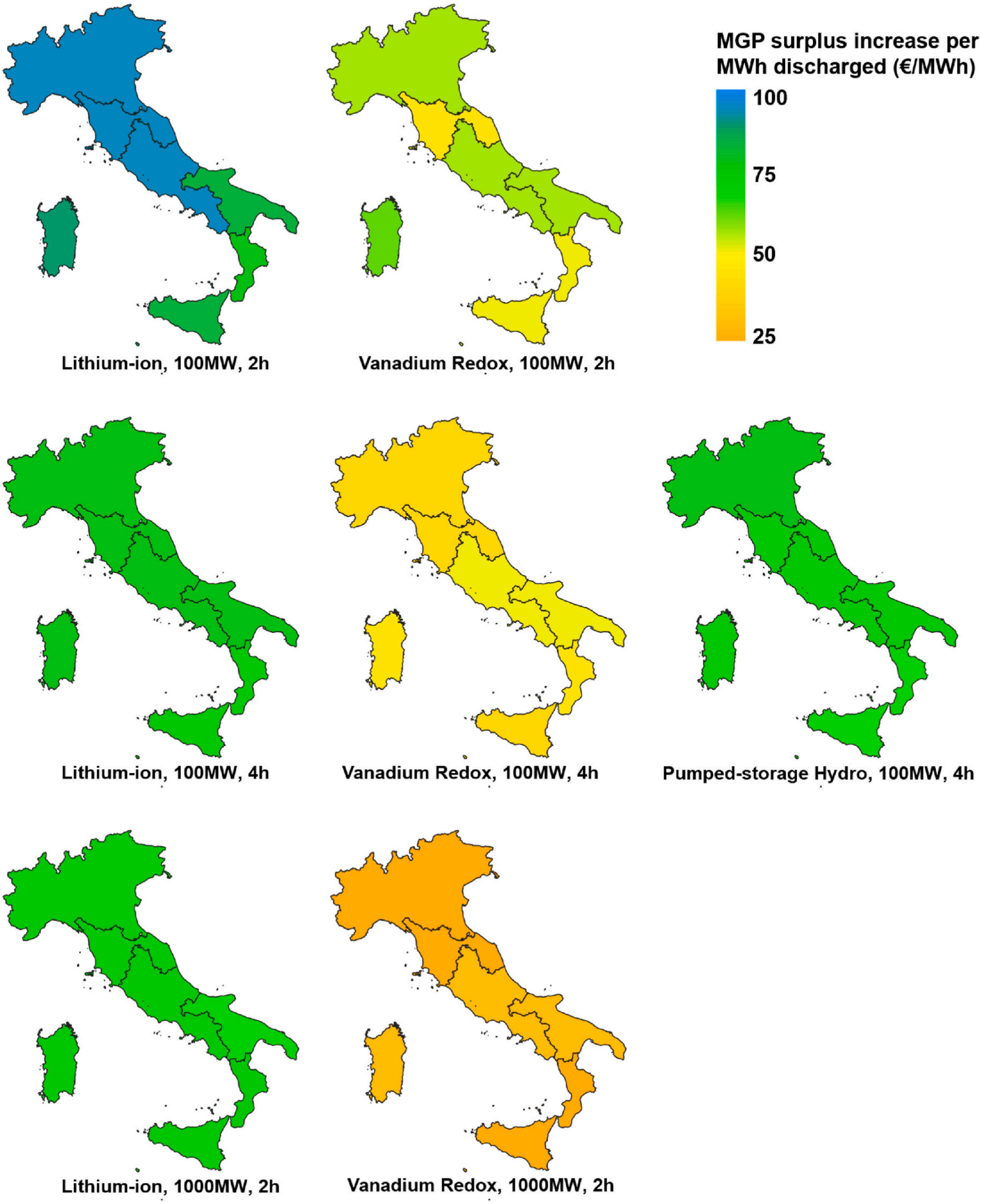
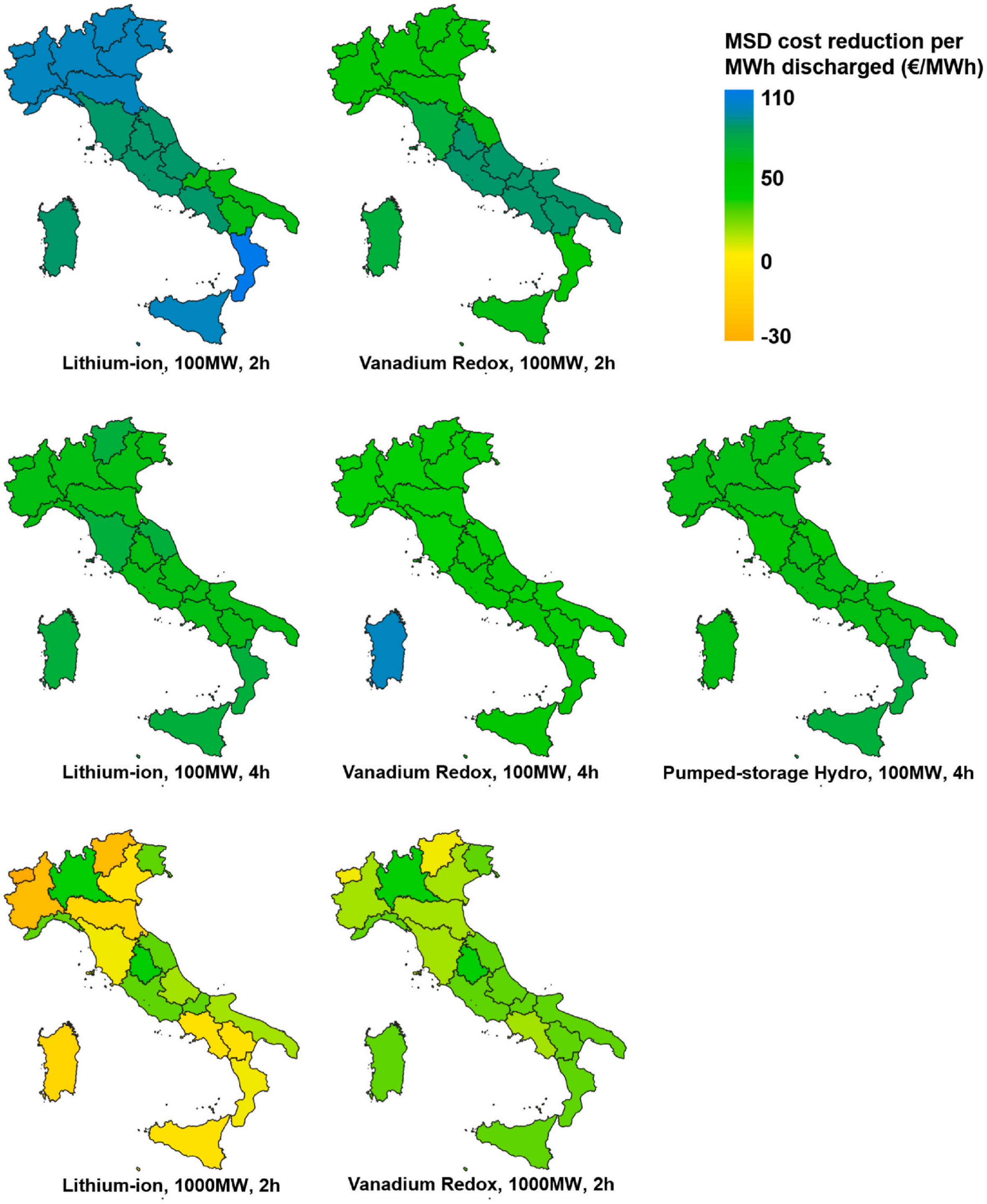


Fig. 5. Market surplus increase in the Italian day-ahead (MGP) per MWh discharged from the energy storage.



Lithium-ion, 100MW, 2h

Vanadium Redox, 100MW, 2h

Lithium-ion, 100MW, 4h

Vanadium Redox, 100MW, 4h

Pumped-storage Hydro, 100MW, 4h

Lithium-ion, 1000MW, 2h

Vanadium Redox, 1000MW, 2h

Fig. 6. Cost reduction achieved in the Italian ancillary services market (MSD) per MWh discharged from the energy storage.

Table 5

Summary of the Impact on Social Welfare		
Technology Comparison	Day-Ahead Market	Ancillary Services Mrk
- Lithium-ion batteries: they are the only assets yielding positive social welfare increase (with 100 MW rated power and 2 or 4-h duration); - Vanadium redox flow batteries: they are not yet competitive at current costs, yielding negative social welfare change; - Pumped-storage hydropower: benefit close to zero or slightly negative once all costs are considered.	- Storage deployment is beneficial across all zones but with varying degrees; - Northern regions (with large industrial centres) showed higher welfare increase; - Decreasing marginal benefit observed as rated power and duration increase; - Highest market surplus achieved by lithium-ion batteries; - Lowest market surplus from vanadium redox storage due to higher round-trip losses.	- Large-scale storage could decrease ancillary services costs by up to €110 per MWh discharged; - Lithium-ion achieves the highest cost reduction due to higher round-trip efficiency; - Benefits decrease as rated power increases; - 1000 MW configurations show negative benefits in some regions due to the "spillover effect" because the markets run sequentially and are not co-optimised.

Table 6

Carbon emission intensities are from (Staffell, 2017; National Grid, 2021; Rogers and Parson, 2019). The values for waste and fossil coal-derived gas technologies are based on our computations, while small-scale generation embedded in lower voltage networks (i.e. below 132 kV) has been assumed carbon neutral.

Technology	kgCO2/MWh
Biomass	120
Fossil Coal-derived gas	872
Fossil Hard coal	937
Fossil Oil	935
Hydro Pumped Storage	0
Hydro Run-of-river and poundage	0
Hydro Water Reservoir	0
Other	300
Solar	0
Waste	593
Wind	0
Gas CCGT	394
Gas OCGT	651
DSR/Embedded generation	0

PUN), while those in areas with high zonal prices benefit from a lower electricity price by paying the PUN. Third, generators face accurate investment price signals (i.e. the zonal prices), highlighting the zones where generation could be more beneficial (as long as intra-zone[4] congestion is negligible). By contrast, by paying the same price all over Italy, large consumers are not incentivised to locate in areas with lower zonal prices, and the averaging effect of the PUN dampens their consumption decrease as a response to a zonal price increase in their area.

The presence of the PUN poses significant challenges during the market clearing. Indeed, regardless of the zonal price in the zone where consumers are located, the following PUN rule must apply:

(1) All demand orders with a submitted price strictly greater than the PUN must be fully accepted (in-the-money orders).
(2) All demand orders with a submitted price strictly less than the PUN must be rejected (out-of-the-money orders).
(3) All orders with a submitted price equal to the PUN can be partially executed (at-the-money orders).

A consequence of this is that within the same zone, it is possible to have one market order from a generator and one market order from a consumer with two different submitted prices, both partially executed, i.e., two marginal users with two different prices in the same zone, which is not possible in a standard economic dispatch. Thus, a specific market-clearing algorithm must be developed. Moreover, enforcing the PUN definition within an optimisation problem is non-trivial, as it induces challenging non-linearities. Indeed, zonal prices are, by definition (Kirschen and Strbac, 2004), the dual variables of the zonal power balance constraints. The computation of the PUN involves multiplication between quantities (MWh) and prices, i.e. primal and dual variables of a market clearing problem, making the PUN definition a non-linear relation. To overcome these challenges, the current algorithm used to solve the Italian market clearing problem adopts a heuristic approach (NEMO, 2020), which iteratively explores the demand curve according to the merit order until a feasible solution that satisfies the PUN rule is found. However, this approach becomes a computationally expensive combinatorial problem in the presence of assets (such as storage) or complex market orders (such as block orders) that introduce coupling between market time intervals. To overcome this issue, the first author of this paper has developed (Savelli et al., 2018) an algorithm to recast the PUN definition as a mixed-integer linear constraint, which has been used to investigate the effect of introducing block orders into the Italian market. The developed approach leverages the fact that the quantities submitted to the Italian day-ahead market must be mandatorily expressed in terms of MWh with at most three decimal digits, meaning that these values can be regarded as integer numbers once expressed in kWh. Hence, using binary variables and standard integer algebra, the Italian market clearing problem with the PUN rule can be recast as a mixed-integer linear problem. The mathematical details and code have been published in (Cornélusse and Savelli, 2018; Savelli et al., 2018) and therefore omitted here for brevity. We will use this approach to solve the Italian day-ahead market clearing with the PUN in the presence of LESS, assuming that the energy storage is managed to maximise the market surplus. This assumption implies that the surplus increase in the MGP (or the reduced cost in the ancillary services market) represents an upper bound of the potential benefit created by the presence of the storage and provides an estimate of the maximum subsidy regulators might pay for supporting storage investors. The Electricity Storage Capacity Procurement Mechanism (MACSE) was recently introduced in Italy (RSE, 2024). Under this new scheme, a storage investor receives a fixed remuneration depending on the energy capacity installed (€/MWh-cap per year) for the length of the contract (15 years in the case of Li-ion battery). The key aspect of this scheme is that the investor that receives the remuneration must build the storage asset and maintain it, but it cannot choose how to operate it. Indeed, charging and discharging possibilities are offered (through standardised time-shifting contracts) to market operators through a market platform, and the TSO communicates the resulting actual charging and discharging profiles to storage owners.

3.2. A model of the Italian ancillary services market

This section describes the methodology used to simulate the Italian ancillary services market, termed “Mercato per il Servizio di Dispacciamento” (MSD), which is used by the Italian transmission system operator (Terna S.p.A.) to manage network congestion, procure reserve, and offset energy imbalances. To perform these activities, the TSO accepts offers in the MSD to increase (decrease) power injections at the required network nodes either by increasing (decreasing) generator

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[4] In the presence of intra-zone congestion (i.e., within the same zone), zonal pricing yields a suboptimal dispatch compared to full nodal pricing, as the TSO has to use the ancillary services market to redispatch the power flows across the network nodes, and the cost of this activity is socialised. A broader discussion on the issues related to cost socialisation, network congestion, ancillary services procurement and markets can be found in (Billimoria et al., 2022, 2023; Paredes et al., 2024; Ren et al., 2024; Savelli et al., 2022, 2023; Savelli et al., 2024; Savelli and Morstyn, 2021, 2023; Xia et al., 2024, 2025).

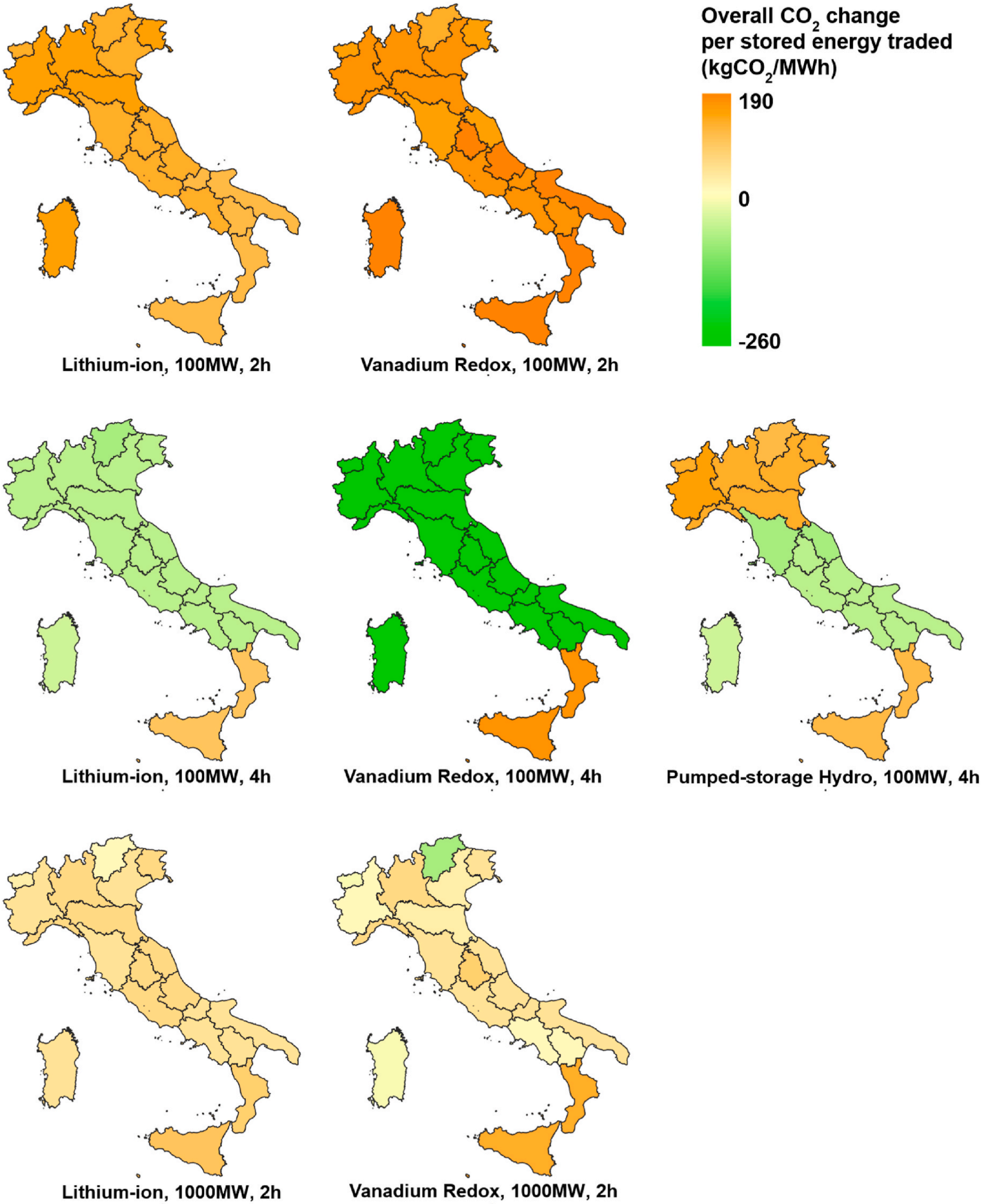

Fig. 7. Carbon emission change considering both day-ahead and MSD markets due to introducing a storage device.

power output or by decreasing (increasing) consumer demand. The MSD is a pay-as-bid market, which means that offers to increase power injection that are accepted receive from the TSO the price they bid. By contrast, the offers to reduce power injection that are accepted pay the TSO the price they bid (as they can save fuel by not producing). We will use the developed redispatching model to simulate the MSD functioning and to estimate (i) how location, rated power, duration, and LESS technology type affect the MSD costs, and (ii) how the different redispatch induced by the presence of storage affects carbon emissions. The MSD runs after the day-ahead market. We assume that the TSO operates the storage at this market stage, considering all results and the charging and discharging profiles scheduled in the day-ahead market. The detailed optimisation problem used to simulate this market is reported in the Supplementary Material. To the best of our knowledge, this model is among the most accurate in the literature and represents a further novelty and an additional contribution to this paper.

3.3. A high-fidelity model of the Italian transmission network

To properly simulate the activities performed by the TSO in the ancillary services market, in addition to the model introduced in the previous section, we also developed a high-fidelity model of the Italian

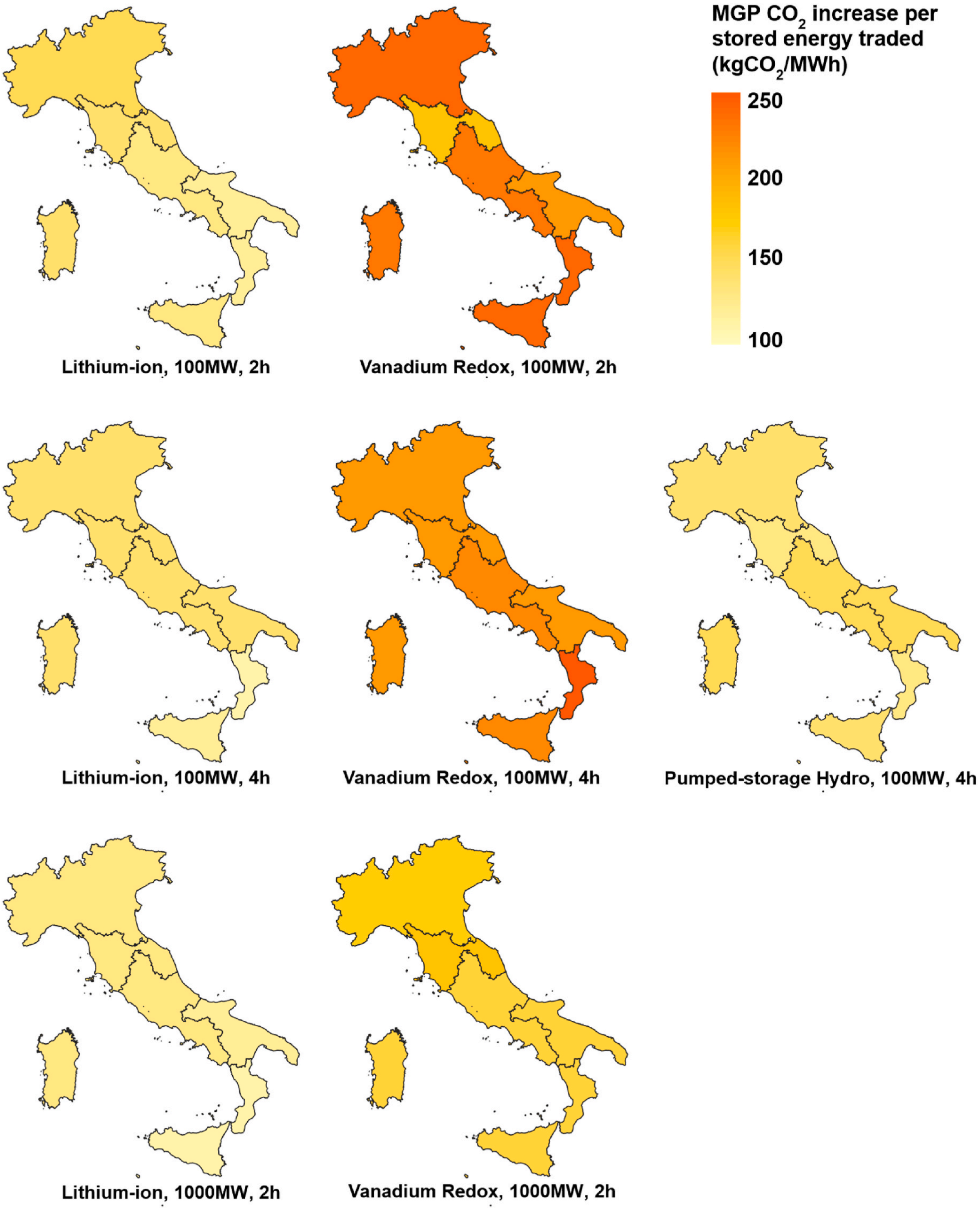

Fig. 8. Carbon emissions increase in the day-ahead market due to the introduction of a storage device.

transmission network. We have used the European high-voltage transmission grid data obtained from EntsoE (EntsoE, 2022), including the existing Italian grid (sketched in Fig. 2) and the planned expansions up to 2025. The EntsoE dataset adopts the Common Grid Model Exchange Standard (EntsoE, 2023b), which has been used to interpret the data. The resulting transmission network consists of 1821 nodes, 937 lines, and 4 HVDC cables connecting Sardinia, Corsica, Montenegro, and France.

4. Test case description, data and settings

The results shown in the following sections have been obtained by comparing a base case with several test cases using the market models and the network described in Section 3. The base case was obtained by simulating the day-ahead market and then the ancillary services market (considering the demand and generation profiles previously accepted in the day-ahead) without introducing any storage devices. By contrast, in each test case, we selected one storage among the seven types considered (see Table 2) and placed it in one of the possible locations in Italy. For the day-ahead market, these locations consist of the seven Italian

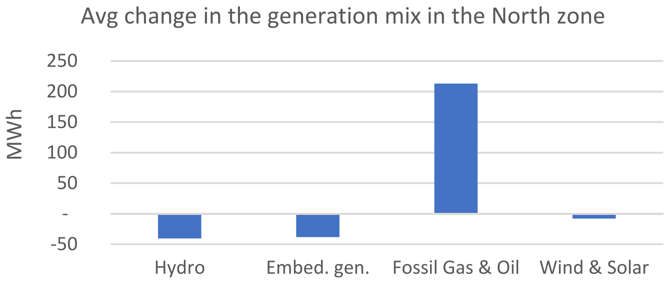

Fig. 9. Average daily change in the generation mix in the North zone due to deploying a Lithium-ion battery with 100 MW rated power and a 4-h duration.

physical zones depicted in Fig. 1, meaning that for the day-ahead market, we tested 49 test cases (one case for each combination of market zones and LESS). Then, given the day-ahead results, we run several instances of the ancillary services market by locating the storage in each region inside each market zone (Table 1 reports the relation between regions and market zones). We assumed the storage is connected to the node with the greatest demand in each region, totalling 140 test cases for the ancillary services markets. For instance, the results for a storage located in the region Lombardy have been obtained by first running the day-ahead market while placing the storage in the North zone and then simulating the ancillary services market assuming that the storage is connected in the node of the network depicted in Fig. 2 with the highest demand in Lombardy.

Fig. 3 graphically represents the procedure used in each test case.

Regarding the electrical grid, for the day-ahead market, we used the Italian zonal network that represents the available transmission capacity between the zones (NEMO, 2020) obtained from the Italian market operator (GME, 2023b). For the MSD, we used the high-fidelity nodal network described in Section 3.2, where we assumed that storage is connected to the node with the greatest demand within each region. This approach allowed us to estimate how the presence of large-scale storage can help increase the day-ahead market surplus and reduce costs in the ancillary services market and how the different redispatch caused by the storage can affect carbon emissions. We initially considered a device with 100 MW rated power and a 2-h duration for lithium-ion and vanadium redox flow batteries. Then, to perform a sensitivity analysis, we also considered the case when the duration increases to 4 h and the case when the rated power increases to 1000 MW. As a further comparison, we included a pumped-storage hydro asset with 100 MW rated power and a 4-h duration (investments with shorter duration are not usually performed for this asset class). Table 2 summarises the different combinations tested.

The data about LESS investment and operation costs has been collected from (Viswanathan et al., 2023) and is reported in Table 3.

For all technologies, the depth of discharge is assumed to be 80 %, and the discount rate (weighted average cost of capital, in real terms) is set to 6.52 %. O&M yearly costs include augmentation and replacement to preserve the operational capability of the energy storage components throughout the project's operational lifetime, assuming a maximum of one complete cycle per day, which is a limitation often imposed by developer's warranties, which is coherent with the daily operation of both the day-ahead and MSD markets. These fixed yearly costs account for, e.g., replacing part of the battery racks in lithium-ion devices (every ~6 years) and the stack and pumps in vanadium redox flow batteries (every ~12 years). Thus, the degradation costs are implicitly factored in the O&M costs (for a detailed discussion about this point, the interested reader is referred to (Viswanathan et al., 2022)).

Given the Capex, O&M, and end-of-life (EoL) costs listed above, an equivalent annual total cost c_k^y for an energy storage system k, in USD, can be computed as shown in Equation (2):

$$\mathrm{c}_k^y = \frac{\mathrm{Capex}_k + \sum_{t=T_c}^{T_c+T_o} \frac{\mathrm{O\&M}_{t,k}}{(1+\mathrm{WACC}_k)^t} + \frac{\mathrm{EoL\ costs}_k}{(1+\mathrm{WACC}_k)^{T_c+T_o}}}{\sum_{t=1}^{T_e} \frac{1}{(1+\mathrm{WACC}_k)^t}} \tag{2}$$

where $\mathrm{T_c}$ is the construction time, $\mathrm{T_o}$ is the operational life, and $\mathrm{T_e}$ is the economic life (years to pay off assets), and WACC_k is the weighted average cost of capital. Given the amount c_k^y, a per hour cost $\mathrm{c_k}$, in Euros, for energy storage system k can be computed as shown in Equation (3):

$$\mathrm{c_k} = \frac{\mathrm{c}_k^y \times \mathrm{CrossRate}^{\$€}}{8760} \tag{3}$$

where the term $\mathrm{CrossRate}^{\$€}$ is the average exchange rate between USD and EUR in 2022, equal to 0.95, and 8760 is the number of hours in one year. The value $\mathrm{c_k}$, reported in the last column of Table 4, is used to represent the hourly cost of adopting the energy storage k, which is necessary to align the lifetime of the different technologies with the period under investigation.

The market data was collected from the Italian market operator (GME, 2023a) and the Italian TSO (Terna, 2023a) and refers to both the first week of July and the first week of December 2022. The network data refers to the EntsoE 2025 future energy scenario (Section 3.3). The models were implemented in Python 3.9 using Pyomo (Bynum et al., 2021) and solved with CPLEX 20.1 (Nickel et al., 2021) on the HPC servers provided by CINECA. Each instance of the day-ahead market clearing problem involves, on average, more than 70,000 market orders each day and is solved in ~40 min. In addition, each instance of the ancillary services market involves more than 9000 market orders daily, on average, and was solved in ~30 min. The models have been validated by comparing the base case with the actual outcomes of the day-ahead and MSD markets. In detail, both the PUN and the cleared quantities obtained by using the model described in Section 3.1 exactly match those observed in the actual day-ahead market, and the order of magnitude of the costs in the ancillary services market (usually ranging between 2€M and 10€M) matches those obtained using the developed model. Note that in the case of the ancillary services market, it is impossible to obtain precisely the same values as we do not have access to all information available to the TSO, such as the location of distributed generation and voltage constraints.

5. Results and discussion

5.1. The economic benefit of introducing LESS

Fig. 4 shows the total benefit (measured as the overall change in social welfare) of introducing LESS in the Italian electricity system considering both the day-ahead and ancillary services markets, net of storage costs (i.e., the value c_k listed in Table 4). The figure highlights that vanadium redox flow batteries are not yet competitive at current costs, yielding a negative social welfare change. Similarly, pumped-storage hydropower leads to a benefit close to zero or slightly negative once all costs are considered, making this technology uncompetitive for short-duration applications. Note that longer-duration pumped-storage hydro and hydroelectric power plants with reservoir or poundage can provide additional services (Terna, 2023b), including seasonal storage, which can provide additional longer-term benefits that are not considered in this work. The interested reader is referred to Hunt et al. (2017, 2018) for a broader discussion. Given current costs, within the configurations considered, the only assets that yield a positive social welfare increase are the lithium-ion devices with 100 MW rated power and duration of both 2 and 4 h. A detailed breakdown of how the day-ahead and ancillary services markets contribute to the overall benefit is shown in Figs. 5 and 6, respectively. Moreover, a sensitivity

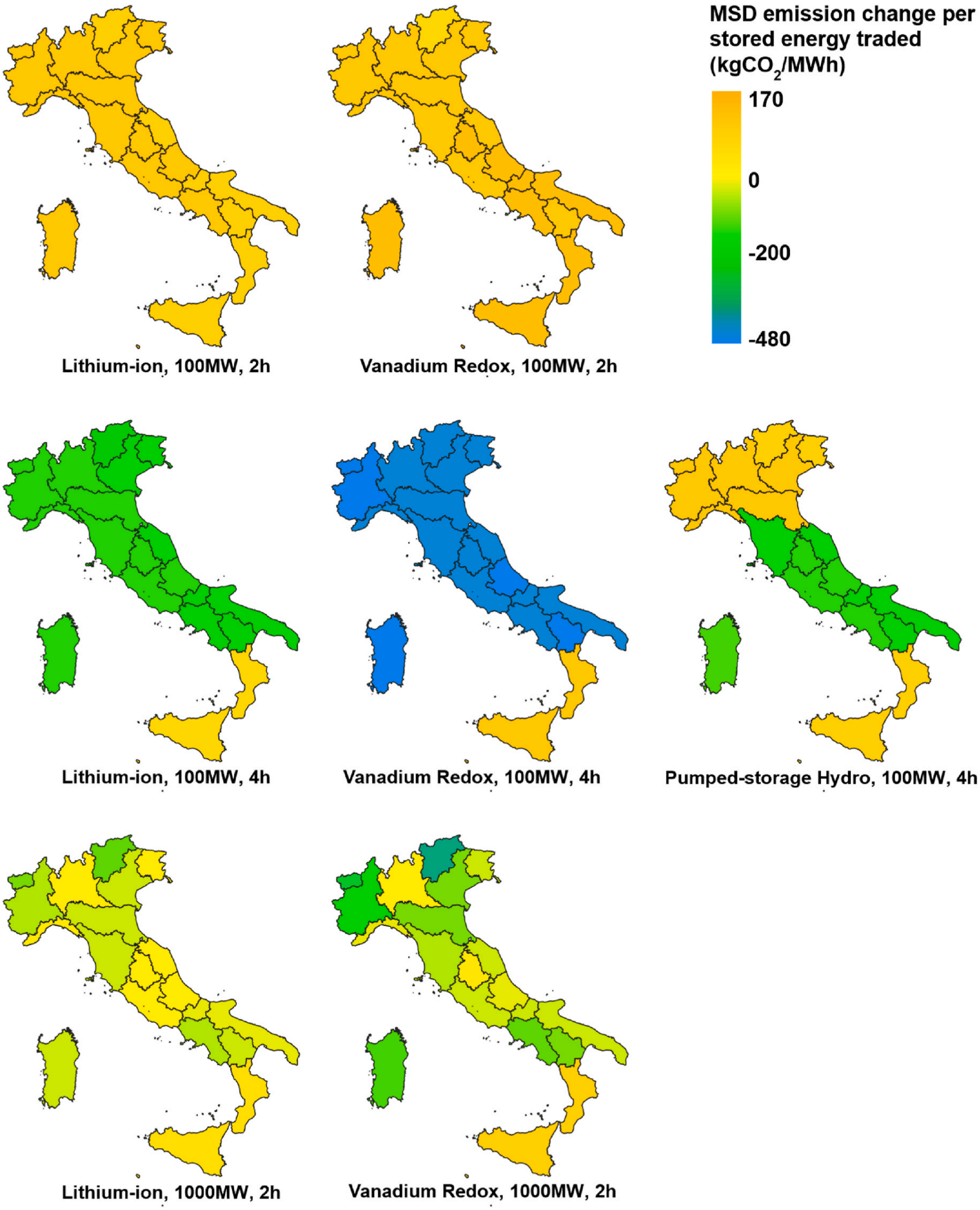

Fig. 10. Carbon emission change in the MSD market due to the introduction of a storage device.

analysis is reported in Appendix A, which assumes an expected investment cost decrease for lithium batteries, vanadium redox flow batteries, and pumped-storage hydro, equal to 20 %, 10 %, and zero, respectively, as estimated in (PNNL, 2024). It highlights the same patterns as those described in Fig. 4, with lithium-ion still being the most promising technology for short-duration storage.

Fig. 5 shows the effect of introducing LESS in the different zones of the Italian day-ahead market. The deployment of a storage system is always beneficial, as it allows the market operator to shift energy between periods to maximise the day-ahead market surplus. However, the actual benefit is not homogeneously distributed and is greater in the northern regions, which have large industrial centres. It is also significantly affected by the technology type and storage-rated power. In particular, the market surplus increase per MWh discharged by the storage decreases as the rated power and duration increase. LESS assets show a decreasing marginal benefit as a function of these two parameters. The lithium-ion battery achieves the highest market surplus increase, while the vanadium redox storage yields the lowest. This result can be explained by the higher round-trip losses of vanadium batteries (round-trip efficiency equal to 65 %) compared to lithium-ion (round-trip efficiency equal to 83 %). Pumped-storage hydropower leads to a market surplus change similar to lithium-ion technology due to the

Table 7

Summary of the Impact on Carbon Emissions		
Technology Comparison	Day-Ahead Market	Ancillary Services Mrk
• The lithium-ion battery with 100 MW and 4-h duration is the only configuration that simultaneously increases social welfare and reduces carbon emissions; • Across all technologies, only the cases with 100 MW rated power and 4-h duration yield apparent carbon emissions reduction.	• All storage technologies increase carbon emissions in the day-ahead market (100–250 kgCO2 per MWh); • Fossil gas generation can increase due to the storage presence; • Storage can act as a market competitor/substitute for hydro-based power plants	• Emissions impact varies significantly by location, duration, and technology; • 2-h duration storage tends to increase emissions; • 4-h duration storage shows abatement benefits; • Vanadium redox flow batteries show emissions reduction potential.

comparable efficiency of 80 %.

Fig. 6 shows the contribution of the ancillary services market to the overall welfare change, computed by allowing the TSO to further utilise the storage to help offset energy imbalances, procure reserve, and solve network constraints, given the profiles scheduled in the day-ahead market. Large-scale storage can decrease the MSD costs by up to 110 € per MWh discharged. Again, the lithium-ion battery achieves the highest cost decrease due to the highest round-trip efficiency. However, the benefit decreases as the rated power of the storage increases and becomes negative in some regions in the 1000 MW case. The reason for the negative benefit (i.e. an increase in the MSD costs) is that the scheduling in the day-ahead market (which is a zonal market; see Section 3.1) performed by the market operator does not account for congestion that may arise near to real-time when the actual nodal network is considered. The TSO manages this congestion in the MSD. As a result, using a large storage system with 1000 MW rated power, the day ahead may increase congestion costs in the MSD, creating a spillover effect between markets (Marques et al., 2022). Table 5 summarises the results of this section.

5.2. The effect of LESS on carbon emissions

The effect on carbon emissions caused by deploying LESS is complex and results from at least two main factors. First, storage can change the generation mix by shifting energy across different periods, leading to a significant decrease or increase in carbon emissions compared to the case without storage (this also implies that the impact depends on the initial energy mix). Second, round-trip efficiency losses can magnify these adverse effects. For example, charging a storage system with an efficiency of 50 % requires twice the energy it will displace on discharge, and if fossil-fuel sources generate this energy, emissions can significantly increase. Table 6 reports the carbon intensities used in this section.

Fig. 7 reports the overall carbon emission change considering both the day-ahead and the MSD markets, showing that only the 100 MW rated power and 4-h duration cases across all technologies yield a clear benefit in terms of carbon emission reduction. Thus, if we consider both Fig. 4 (which shows the change in social welfare) and this figure (which reports the overall effect on carbon emissions), the only technology that yields, at the same time, a social welfare increase and a carbon emission reduction is a lithium-ion battery with 100 MW rated power and duration of 4 h, which therefore appears to be the most beneficial storage type, given current investment costs and considering the daily time horizon of the analysed markets. A breakdown of the contributions to carbon emission change of the day-ahead and the MSD markets is reported in Figs. 8 and 10, respectively.

Fig. 8 shows the effect of introducing a storage device to the Italian day-ahead market on carbon emissions. Regardless of the technology, LESS can cause a non-negligible increase in carbon emissions in all zones, which range from 100 kgCO2 to 250 kgCO2 per MWh of energy exchanged by the storage. This result means that, on average, the storage device is charged with dirtier sources than those it displaces when discharged. In particular, a typical pattern that emerges in all zones is that fossil gas technologies (the most common marginal units in the Italian market) tend to increase their generation in the presence of storage while existing pumped-storage hydro and hydroelectric reservoir technologies are utilised less frequently. LESS can act as a market competitor or substitute for hydro-based power plants, which is a result also observed in (Oliva H. & Muñoz, 2021) for the Chilean energy system. For example, Fig. 9 reports the average daily change in the generation mix in the North zone in the case of lithium-ion, which has 100 MW rated power and a 4-h duration. Note that wind and solar power are negatively affected. The reason is that even though wind and solar have near-to-zero marginal costs, their actual bid price can be significantly higher (more than 50 €/MWh sometimes); their offers are not necessarily the lowest in the market.[5] Therefore, they might not be used to charge the storage and instead displaced during the discharging phase, reducing their presence in the generation mix. Moreover, if lower-cost gas turbines are used in the charging phases, and even assuming that they are displaced in the discharging phase, the round-trip losses will still cause a net increase in gas usage, increasing emissions.

Finally, Fig. 10 shows the change in carbon emission in the ancillary services market, highlighting some interesting aspects. First, the change in carbon emission is not homogeneous but varies significantly with location, duration, and technology type. Batteries with a 2-h duration tend to increase carbon emissions in the ancillary services market, while longer-duration storage tends to have a beneficial effect on emissions, with a clear benefit in the 4-h case. Moreover, in the case of vanadium redox flow batteries, the reduction in carbon emission appears significantly more than in all other cases. This result can be explained as these assets have a low utilisation rate (well below 50 % in the 4-h case) due to their low round-trip efficiency, and, when used, they primarily displace hard-coal power plants. Note that the reported analysis depends on EntsoE datasets, but actual network and market conditions and technology costs could evolve differently. Moreover, the study focuses on day-ahead and ancillary services markets, but additional longer-term benefits could be provided by some technologies like pumped-storage hydro, e.g. through seasonal storage. Finally, we remark that we do not have access to all information available to TSOs, such as the location of distributed generation and voltage constraints. Table 7 summarises the results of this section.

6. Conclusion and policy implications

Reaching net-zero carbon emissions by 2050 requires deploying a significant amount of large-scale energy storage systems, which can significantly impact electricity markets. In this work, we investigated how storage technology, location, rated power, and duration can affect carbon emissions and social welfare, focusing on a 2025 scenario for the Italian energy system. We modelled the two main electricity markets in Italy, i.e., the day-ahead market, which is a zonal market subject to the PUN rule, and the ancillary services market, which the transmission system operator uses to solve network congestion, procure reserve, and

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[5] In the coming years, the increase of renewable penetration will increase the competition among these assets, and their bid prices are expected to revert towards their marginal costs, removing this market distortion.

offset energy imbalances. A high-fidelity model of the Italian transmission network with more than 1800 nodes has also been developed.

The results show that large-scale energy storage systems can significantly affect social welfare and carbon emissions. In terms of market surplus, deploying a storage device in the day-ahead market is always beneficial. However, this may increase costs in the ancillary services market (due to the spillover effect) because these markets run sequentially and are not co-optimised. Our findings highlight that the spillover increases as the storage-rated power increases. It also implies a diminishing marginal benefit created by the storage per unit of power installed. Location, technology, rated power, and duration can significantly impact grid carbon emissions change, varying between −260 kgCO2 and 190 kgCO2 per MWh traded by energy storage. Importantly, deploying LESS can help reduce fossil fuel-based power production in the central and northern regions in the ancillary services market. It could also reduce the utilisation of hydroelectric power, acting as a substitute, and increase fossil gas power generation in the day-ahead market with negligible effect on renewables. This result can be explained by the relatively high bidding price of solar and wind power plants (more than their marginal costs) in the day-ahead market, which reduces the chances of the storage being charged from renewable energy while favouring fossil fuel generation. However, this price distortion will decline as wind and solar penetration increases. Given current storage investment costs and considering the daily time horizon of the day-ahead and ancillary services markets, the most beneficial asset regarding social welfare increase and carbon emission reduction appears to be a lithium-ion battery with 100 MW rated power and a 4-h duration. However, future scenarios may diverge from today's investment cost trends, and storage technologies currently at a disadvantage for lithium-ion batteries might become more competitive, e.g., due to unexpected technological breakthroughs (Schmidt et al., 2017).

These results suggest that policymakers should adequately consider the potential impact on welfare and emissions that large-scale energy storage systems may have, as these assets can help increase social welfare but may also induce spillover effects across energy markets, with a mixed result on carbon emissions. Therefore, they should prioritise investment incentives for technologies that demonstrate economic and environmental benefits. A practical implication for policymakers is the importance of designing targeted support schemes for technologies and projects that can deliver these dual benefits, ensuring that investments contribute to overall system welfare and emission reductions. Our findings also show the importance of accounting for the interplay between different markets when considering electricity market reforms and storage investments. Adopting a forward-looking approach can help better understand and plan for the evolving energy landscape and the role of LESS within it. Regulators might also consider revising market regulations to foster the development of mechanisms to co-optimise energy markets that account for the interaction between day-ahead and ancillary services markets, aiming to mitigate potential spillover effects and minimise unintended consequences on costs and emissions. This approach includes accounting for this effect in the TSO's Bidding Zone Review process (EntsoE, 2023a) (i.e., the periodic process of defining the borders between market zones), as well as designing specific strategies and mechanisms for co-optimising these markets, such as integrated market platforms (e.g., for the partial procurement of reserve and congestion management resources at the day-ahead stage) and developing advanced forecasting tools to better manage congestion and real-time market dynamics (Ji et al., 2016).

Future work will aim at broadening these results by (i) introducing additional ancillary services, such as frequency response; (ii) widening the considered time horizon; and (iii) introducing long-duration technologies, such as compressed air and hydrogen energy storage systems.

CRediT authorship contribution statement

Iacopo Savelli: Writing – original draft, Project administration, Methodology, Funding acquisition, Formal analysis, Data curation, Conceptualization. **David Howey:** Writing – review & editing, Conceptualization. **Thomas Morstyn:** Writing – review & editing, Conceptualization.

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.

Acknowledgements

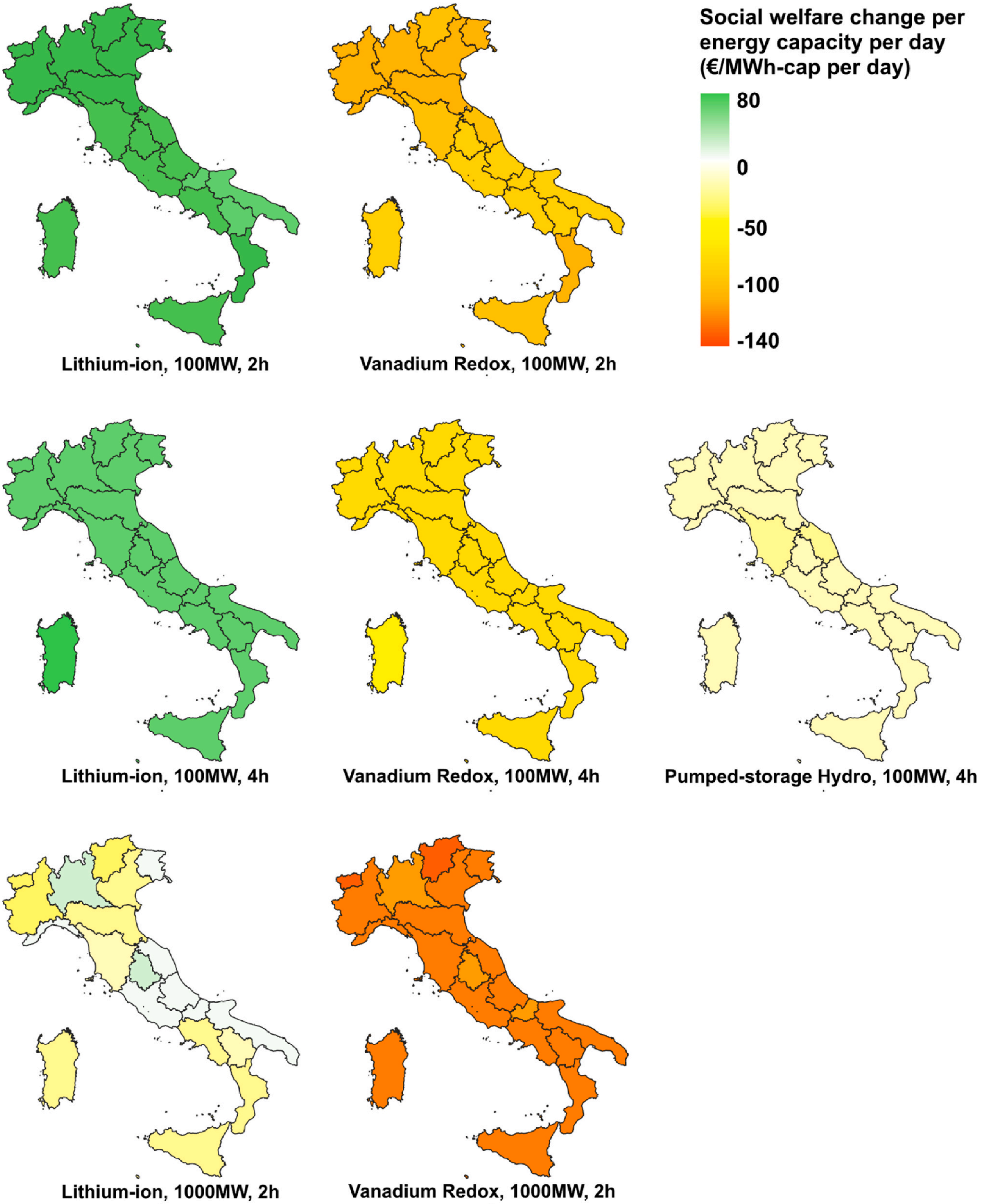
Iacopo Savelli acknowledges the support from the Recovery and Resilience Plan - Mission 4 – Subfield: "Projects presented by young researchers", project number SOE_0000029 and CUP J47G22000430001, and the CINECA award (ref. HP10C6OTYJ) under the ISCRA initiative for the availability of high-performance computing resources and support. David Howey and Thomas Morstyn acknowledge UKRI EPSRC funding under the project "Data-driven exploration of the carbon emissions impact of grid energy storage deployment and dispatch" (ref. EP/W027321/1).

Appendix. ASupplementary Material

Supplementary material to this article can be found online at https://doi.org/10.1016/j.jup.2025.101937.

Appendix A. Sensitivity Analysis

The US Department of Energy's Energy Storage Grand Challenge (PNNL, 2024) recently estimated an investment cost decrease in the period 2023–2030 for lithium batteries, vanadium redox flow batteries, and pumped-storage hydro, approximately equal to 20 %, 10 %, and zero, respectively. Similarly to Figs. 4 and 11 shows the overall welfare change obtained by reducing the storage investment costs by these percentages. The figure highlights the same patterns as those shown in Fig. 4, with lithium-ion being the most promising technology for short-duration storage.


Lithium-ion, 100MW, 2h

Vanadium Redox, 100MW, 2h

Lithium-ion, 100MW, 4h

Vanadium Redox, 100MW, 4h

Pumped-storage Hydro, 100MW, 4h

Lithium-ion, 1000MW, 2h

Vanadium Redox, 1000MW, 2h

Fig. 11. Similarly to Fig. 4, this figure shows the social welfare change due to the LESS introduction, but considering a cost reduction for Lithium-ion batteries, Vanadium redox batteries and pumper-storage hydro equal to 20 %, 10 % and 0 %, respectively.

Appendix B. Glossary

Acronym	Meaning
Capex	Capital Expenditures
CCGT	Closed-cycle gas turbine
DSR	Demand-side response
EoL	End of Life
HPC	High-Performance Computing
HVDC	High-Voltage Direct Current cable
LESS	Large-scale energy storage systems
MGP	Day-ahead market, in Italian: “Mercato del Giorno Prima”
MSD	Ancillary Services market, in Italian “Mercato per il Servizio di Dispacciamento”
OCGT	Open-cycle gas turbine
O&M	Operation and Management costs
PUN	Unique National Price, literally “Prezzo Unico Nazionale”
TSO	Transmission System Operators
WACC	Weighted average cost of capital

Data availability

The authors do not have permission to share data.

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