Location matters for large-scale energy storage policy: spillover effects for balancing costs and carbon emissions across Italy

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Abstract
Reaching net zero requires substantial deployment of large-scale energy storage systems (LESS), which can significantly affect electricity markets. Here, we investigate how LESS location, rated power, duration, and technology can affect welfare and carbon emissions in the Italian electricity system. We modelled both 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, but can also induce unintended consequences, such as spillovers across markets with a mixed effect on emissions.

Keywords: energy storage; carbon emission; Italy; ancillary services; day-ahead market

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1. Introduction

Large-scale energy storage systems (LESS) are essential assets to foster the decarbonisation of the electricity sector and support the massive deployment of intermittent renewable sources. It is projected that achieving net-zero power grids requires a global LESS deployment of 1.5-2.5 TW and 85-140 TWh by 2040, accounting for 10% of electricity consumed worldwide, with an estimated investment of up to $3 trillion (Sánchez-Pérez et al., 2022). Pumped hydro energy storage has long supported power grids during peak times, but this is no longer sufficient, and orders of magnitude more energy storage capacity is required (EntsoE, 2023c). The deployment of non-hydro grid storage, mostly lithium-ion batteries, is growing in popularity driven by rapid battery cost decline (13% per year from 1992-2016 (Ziegler & Trancik, 2021)), and increasing revenue streams, such as trading in electricity markets. However, LESS operation does not necessarily align with the environmental goal of reducing carbon emissions. For example, wholesale arbitrage by storage owners may increase emissions in some power grids by shifting the generation mix towards dirtier sources, and round-trip efficiency losses can exacerbate this effect (Beuse et al., 2021). Consequently, it is important to investigate how the substantial deployment of LESS required to reach net zero can affect energy markets, and the effect that this can have on social welfare and carbon emissions. The *social welfare* is formally defined as the sum of the consumers' surplus, the producers' surplus, and the congestion rent, net of investment costs (Kirschen & Strbac, 2004). In the following, we will also use the term *market surplus* to focus on the welfare of a specific market without accounting for investment costs.

The aim of this paper is to help inform policymakers on how the technology type, rated power, duration[2], and location of LESS can affect welfare and carbon emissions, with a focus on the Italian electricity system. In detail, we will compare a base case without LESS with several test cases, obtained 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; Lai & Locatelli, 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, the presence of storage may help reduce the dependence on fossil fuel-based generation in the central and northern regions in the ancillary services market, but in the day-ahead market it may reduce the utilisation of hydropower, acting as a substitute, resulting in an increase of fossil gas generation. We also observed a non-negligible spillover effect (see Section 4.2) between day-ahead and ancillary services markets caused by the presence of LESS, which can increase

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

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 useful evidence that may help shape the current EU regulatory framework on energy storage (DG 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.

2. Literature review

In the literature, a comprehensive analysis of the effect of introducing LESS in the European countries was reported in Beuse et al., (2021). Using 2018 data, they analysed seven different 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 the presence of LESS can range from negative 250 kgCO2 per MWh discharged in countries like France, to positive 500 kgCO2/MWh in coal-dependent countries such as 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 tCO2/MWh, which reaches -0.17 tCO2/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 the introduction of 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.

The effect of LESS on the US energy system was investigated by several authors. Cavicchi & 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 with the sole objective of minimising their electricity bill. This implies that the decentralisation of energy storage might not necessarily help decarbonise the energy system. By contrast, when operated with the goal of minimising emissions, they can reduce average household emissions by 2.2–6.4%, but this involves a cost ranging from $180 to $5,160 per tCO2 avoided. Fares & 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) and Pimm et al., (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 is used to offset power imbalances with little 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 can outweigh investment costs by more than 20% at 2017 prices. Yagi & 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 reported by Goteti et al., (2021). They show that current marginal units, mainly gas turbines, can lose most of their operating income because they can be displaced by energy storage, and may be forced to retire in the long term. Finally, 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.

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.

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 Figure 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 located in the Italian physical zones in Figure 1 are cleared at the same price, termed Unique National Price, or PUN (Savelli et al., 2018). Formally, the $\mathrm{PUN_t}$ 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' demand $D_{t,n}$, that is:

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

$$\mathrm{PUN_t} = \frac{\sum_{n \in N} D_{t,n} \pi_{t,n}}{\sum_{n \in N} D_{t,n}}$$

This definition 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 is important, as it 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 (Hogan, 1992; 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 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[3] 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:

[3] 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, and ancillary services markets can be found in (Billimoria et al., 2022a, 2022b; Savelli et al., 2022, 2023; Savelli & Morstyn, 2021, 2023).

- all demand orders with a submitted price strictly greater than the PUN must be fully accepted (in-the-money orders)
- all demand orders with a submitted price strictly smaller than the PUN must be rejected (out-of-the-money orders), and
- 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. This means that 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 & Strbac, 2004), the dual variables of the zonal power balance constraints. This means that 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 also 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 in (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 expressed in terms of MWh with at most three decimal digits, mandatorily. This means that these values can be regarded as integer numbers once expressed in kWh. Hence, by 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 have been published in (Savelli et al., 2018) and therefore omitted here for the sake of 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 ancillary services cost in the MSD) 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. Note also that 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, the charging and discharging possibility is offered (through standardized time-shifting contracts) to market operators through a market platform, and the resulting actual charging and discharging profiles are communicated to the storage owners by the TSO.

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 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 have bid. By contrast, the offers to reduce power injection that are accepted *pay* to the TSO the price they have 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. At this market stage, we assume that the storage is operated by the TSO, considering all results and the charging and discharging profiles scheduled in the day-ahead market. The detailed optimization problem used to simulate this market is reported in the Supplementary Material available at (Savelli et al., 2024).

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 transmission network. We have used the data of the European high-voltage transmission grid obtained from EntsoE (EntsoE, 2022), which includes the existing Italian grid (sketched in Figure 2), as well as 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 1,821 nodes, 937 lines, and 4 HVDC cables connecting Sardinia, Corsica, Montenegro, and France.

Figure 2 The Italian high-voltage transmission network.

4. Results and discussion

4.1. Test case description 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 has been 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. In contrast, in the test cases we added storage devices in different locations. For the day-ahead market, these locations consist of each of the seven Italian physical zones depicted in Figure 1, while for the ancillary services market we considered each of the twenty Italian regions, as there is a direct relation between them and the day-ahead market zones, shown in Table 1.

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

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 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. For lithium-ion and vanadium redox flow batteries, we initially considered a device with 100 MW rated power and a 2 h duration. 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 1,000 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.

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

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

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

Parameters	Unit of Measure	Lithium	Lithium	Lithium	Vanadium Redox	Vanadium Redox	Vanadium Redox	Pumped-storage Hydro
Capex	$\$/kWh_{cap}$	427.18	385.21	399.72	708.15	505.88	672.27	511.00
O&M	$\$/kW_{cap}$-y	2.56	4.27	2.37	4.44	6.16	4.24	28.10
End-of-life costs	$\$/kWh_{cap}$	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 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 both 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).

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 full 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). This also means that 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 $\mathrm{c}_\mathrm{k}^\mathrm{y}$ for an energy storage system k, in USD, can be computed as follows:

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

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). Given the amount $\mathrm{c}_\mathrm{k}^\mathrm{y}$, a per hour cost $\mathrm{c_k}$, in Euros, for energy storage system k can be computed as:

$$\mathrm{c_k} = \frac{\mathrm{c}_\mathrm{k}^\mathrm{y} \times \mathrm{CrossRate}^{\$€}}{8760}$$

where the term $\mathrm{CrossRate}^{\$€}$ is the average exchange rate between USD and EUR in 2022, equal to 0.95, and 8,760 is the number of hours in one year. The value $\mathrm{c_k}$, reported in the last column of Table 4, will be 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 time period under investigation.

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

Table 4 The table summarises the equivalent hourly costs for the considered storage technologies.

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 (see Section 3.3). To reduce the computational complexity, neighbouring countries (e.g. France) are not explicitly modelled, and the hourly cross-border flows have been considered fixed and equal to the actual hourly import/export obtained from the Italian market operator. This means that the obtained results might be affected if all European countries were modelled jointly. However, we remark that all foreign operators that are allowed to bid in the Italian virtual zones are explicitly included in our model. 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 was solved in ~40 minutes, while each instance of the ancillary services market involves more than 9,000 market orders each day, on average, and was solved in ~30 minutes. The models have been validated by comparing the base case with the actual outcomes of both 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 not possible to obtain precisely the same values as we don't have access to all information available to the TSO, such as the location of distributed generation and voltage constraints.

4.2. The economic benefit of introducing LESS

Figure 3 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, as well as 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. For a broader discussion on this point, the interested reader is referred to e.g. Hunt et al., (2017, 2018). 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 h and 4 h. A detailed breakdown of how the day-ahead and ancillary services markets contribute to the overall benefit is shown in Figure 4 and Figure 5, respectively.

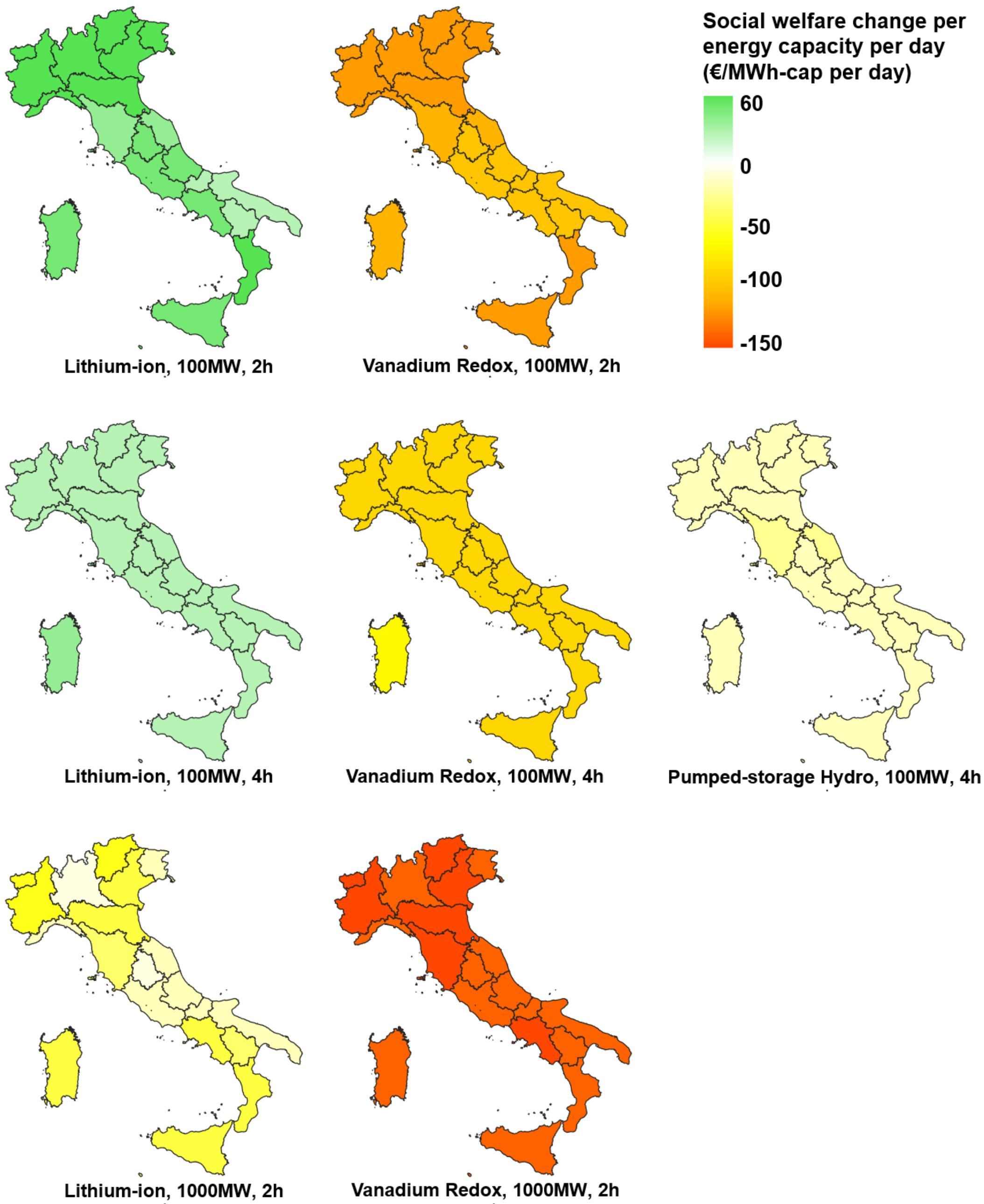

Figure 3 Social welfare change due to the LESS introduction in the Italian day-ahead and ancillary services markets, considering storage costs. The values are reported in terms of daily benefit per MWh of installed energy capacity.

Figure 4 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 time periods to maximise the day-ahead market surplus. However, the actual benefit is not homogeneously distributed and is greater in the northern regions, which are characterised by 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. That is, LESS show a decreasing marginal benefit as a function of these two parameters. The highest market surplus increase is achieved by the lithium-ion battery, while the vanadium redox storage yields the lowest one. This 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 comparable efficiency, equal to 80%.

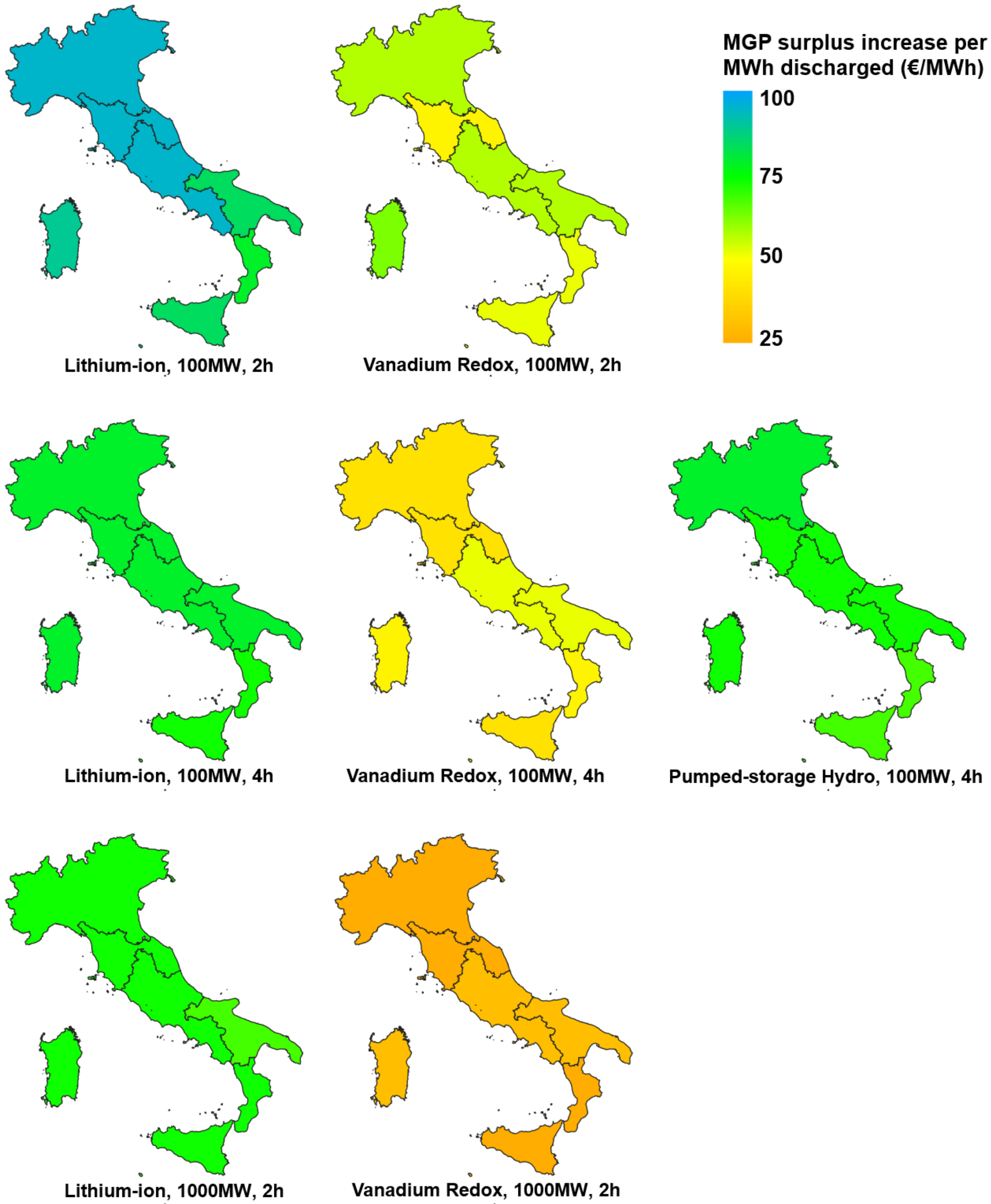

Figure 4 Market surplus increase in the Italian day-ahead (MGP) per MWh discharged from the energy storage.

Figure 5 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. The presence of a large-scale storage can contribute to decreasing 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 1,000 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. This congestion is managed by the TSO in the MSD. As a result, by using a large storage system with 1,000 MW rated power, the market operator in the day-ahead may actually end up increasing congestion costs in the MSD. This can be regarded as a spillover effect between energy markets (Buchsbaum et al., 2020; Chuliá et al., 2019).

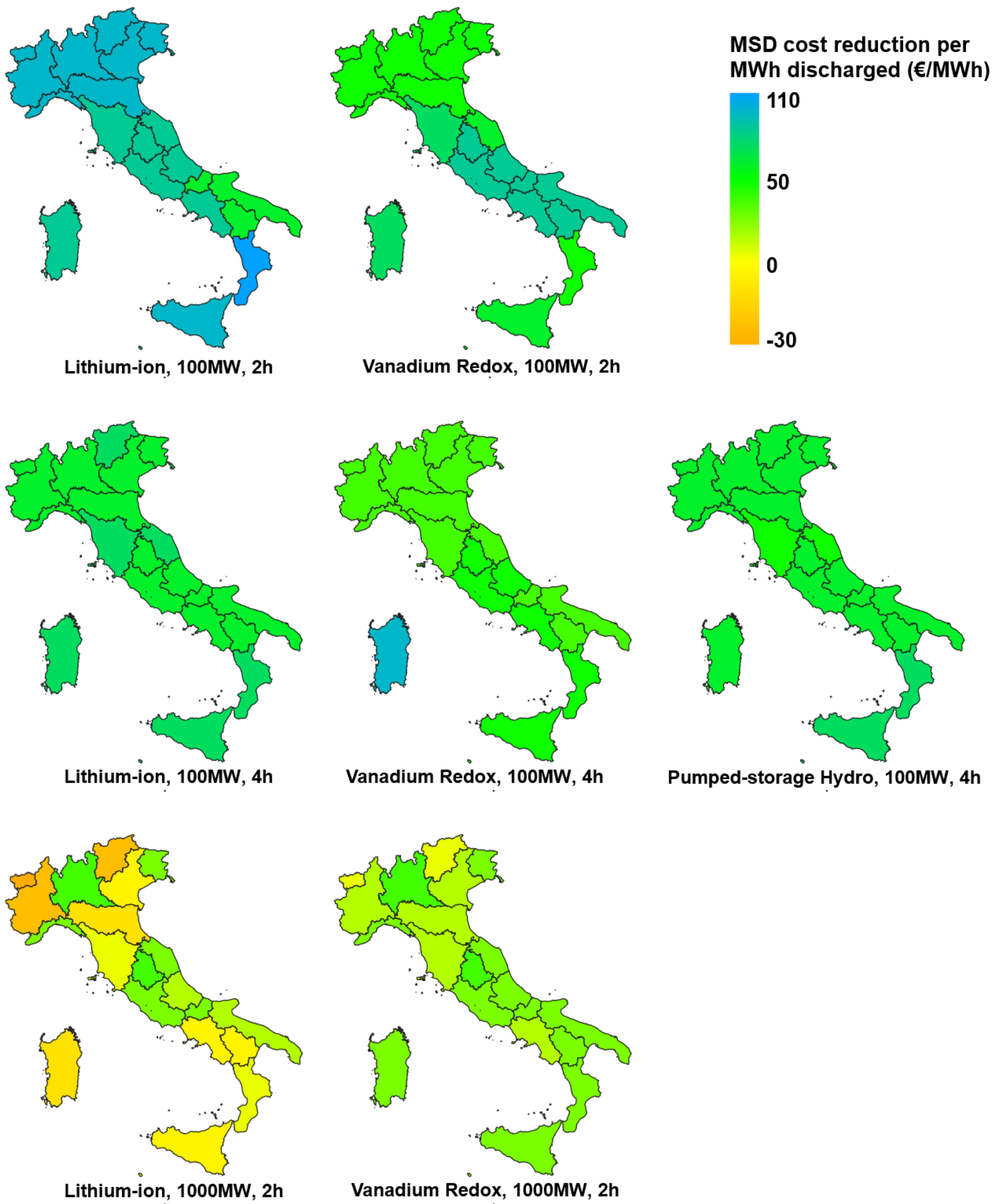

Figure 5 Cost reduction achieved in the Italian ancillary services market (MSD) per MWh discharged from the energy storage.

4.3. The effect of LESS on carbon emissions

The effect on carbon emissions caused by deploying LESS is complex and is the result of (at least) two main factors. First, storage can induce a change in the generation mix by shifting energy across different time periods, which can lead to a significant decrease or increase in carbon emissions compared to the case without storage (this also implies that the impact is dependent on the initial energy mix). Second, the round-trip efficiency losses can exacerbate this change, and the effect is greater the smaller the round-trip efficiency. The reason is that, 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, then the end result is that emissions can significantly increase. Table 5 reports the carbon intensities used in this section.

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

Table 5 Carbon emission intensities are from (Staffell, 2017)*,* (National Grid, 2021)*, and* (Rogers & 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.*

Figure 6 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. This means that if we consider both Figure 3 (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 the 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 Figure 7 and Figure 10, respectively.

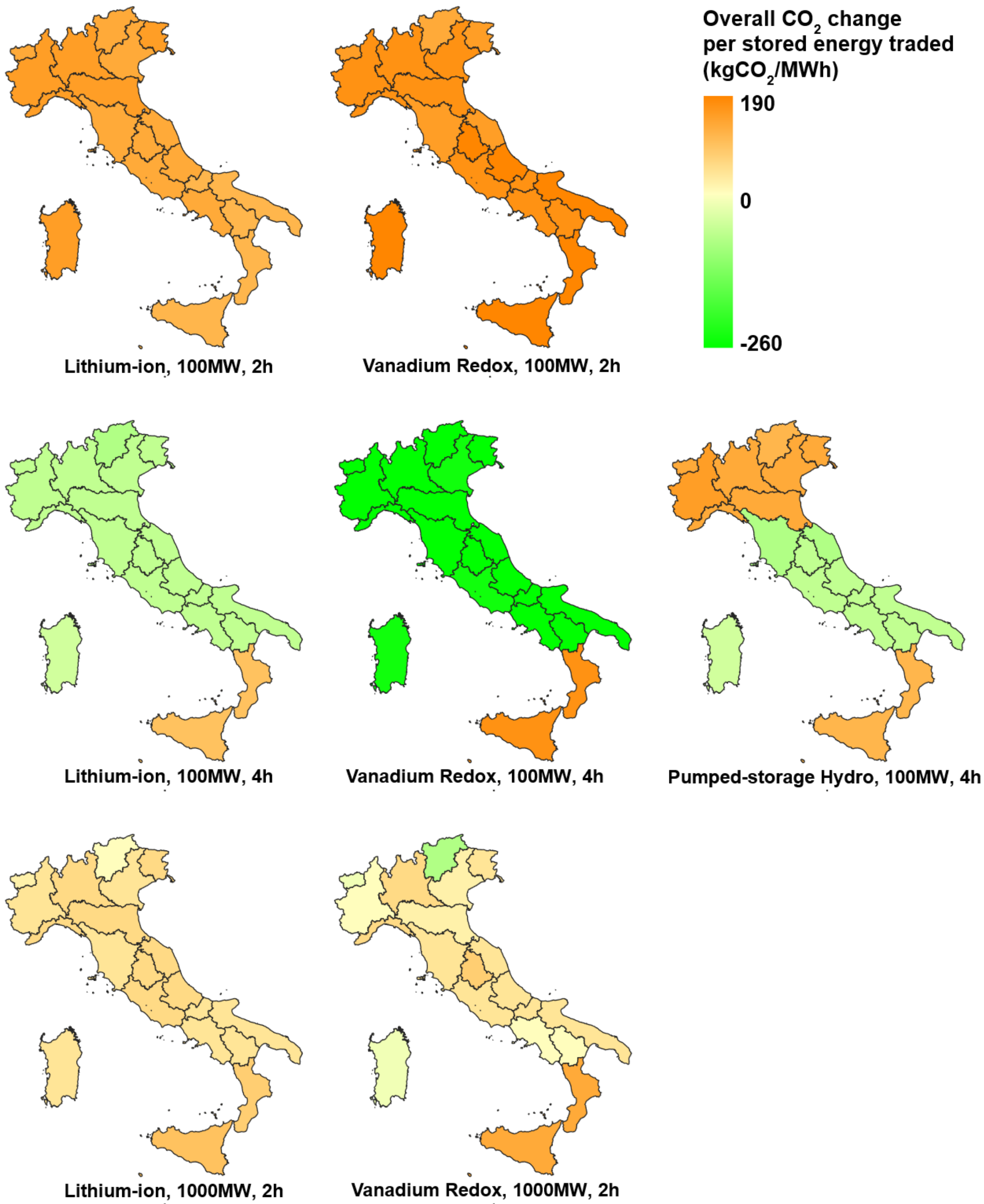

Figure 6 Carbon emission change considering both day-ahead and MSD markets due to the introduction of a storage device.

Figure 7 shows the effect on carbon emissions of introducing a storage device in the Italian day-ahead market. Regardless of the technology, LESS can cause a non-negligible increase in carbon emissions in all zones, which ranges from 100 kgCO2 to 250 kgCO2 per MWh of energy exchanged by the storage. This means that the storage device is charged, on average, 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. This means 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. As an example, Figure 8 reports the average daily change in the generation mix in the North zone in the case of Lithium-ion with 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 (greater than 50 €/MWh in some cases). This means that their offers are not necessarily the cheapest ones in the market[4]. Therefore, they may not be used to charge the storage, and may be instead displaced during the discharging phase, *reducing* their presence in the generation mix. Moreover, if cheaper gas turbines are used in the charging phases, and even assuming that they are then displaced in the discharging phase, the round-trip losses will still cause a net increase in gas usage, increasing emissions. As a further test case, Figure 9 reports the results that would be obtained if the bid prices of renewable assets (wind, solar and non-pumped hydro) were zero instead. In this case, the generation from gas and oil power plants would significantly decrease, while renewable generation would increase, particularly hydropower. The solar and wind power variation is more limited, as the results show that storage is charged at night when it cannot benefit from photovoltaic energy, and there is a limited amount of deployed wind generation. In the current Italian generation mix, there are still coal-based power plants (planned to be phased out before 2030) that are used during the storage charging phase. Nevertheless, storage would provide a beneficial overall contribution to carbon abatement, reducing emissions by 24 tCO_2 in the period considered. As renewable penetration increases, competition will drive offer prices of wind and solar power plants towards their near-to-zero marginal costs, and storage will help avoid renewable curtailment by charging at periods of excess renewable generation, when prices will be close to zero (or even negative) while discharging at demand peak time, reducing carbon emissions.

[4] 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.

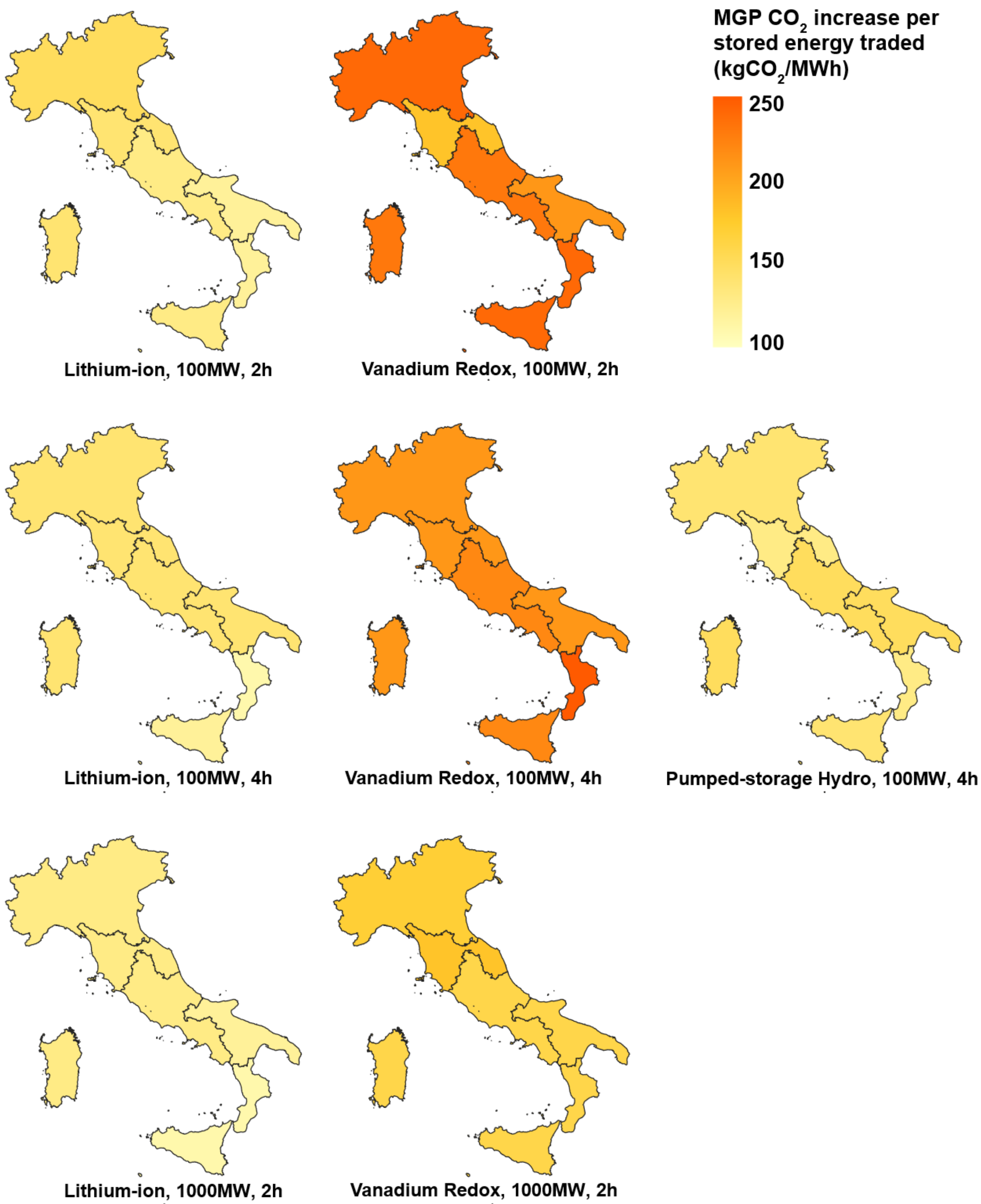

Figure 7 Carbon emissions increase in the day-ahead market due to the introduction of a storage device.

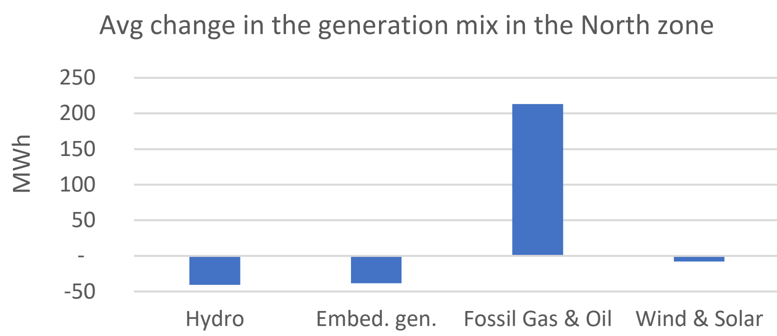

Figure 8 Average daily change in the generation mix in the North zone due to deploying a Lithium-ion battery with 100 MW rated power and a 4 h duration.

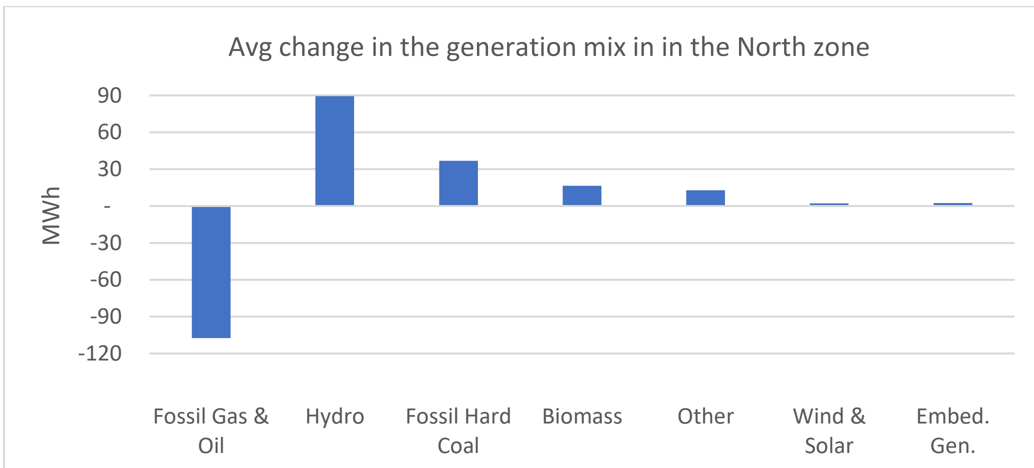

Figure 9 Average daily change in the generation mix in the North zone due to deploying a Lithium-ion battery with 100 MW rated power and a 4 h duration, assuming that wind, solar, reservoir-based hydro, and run-of-river hydro plants have bid prices equal to zero.

Finally, Figure 10 shows the carbon emission change 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 in terms of emissions, with a clear benefit in the 4 h case. Moreover, in the case of vanadium redox flow battery the carbon emission reduction appears significantly greater than in all other cases. This 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.

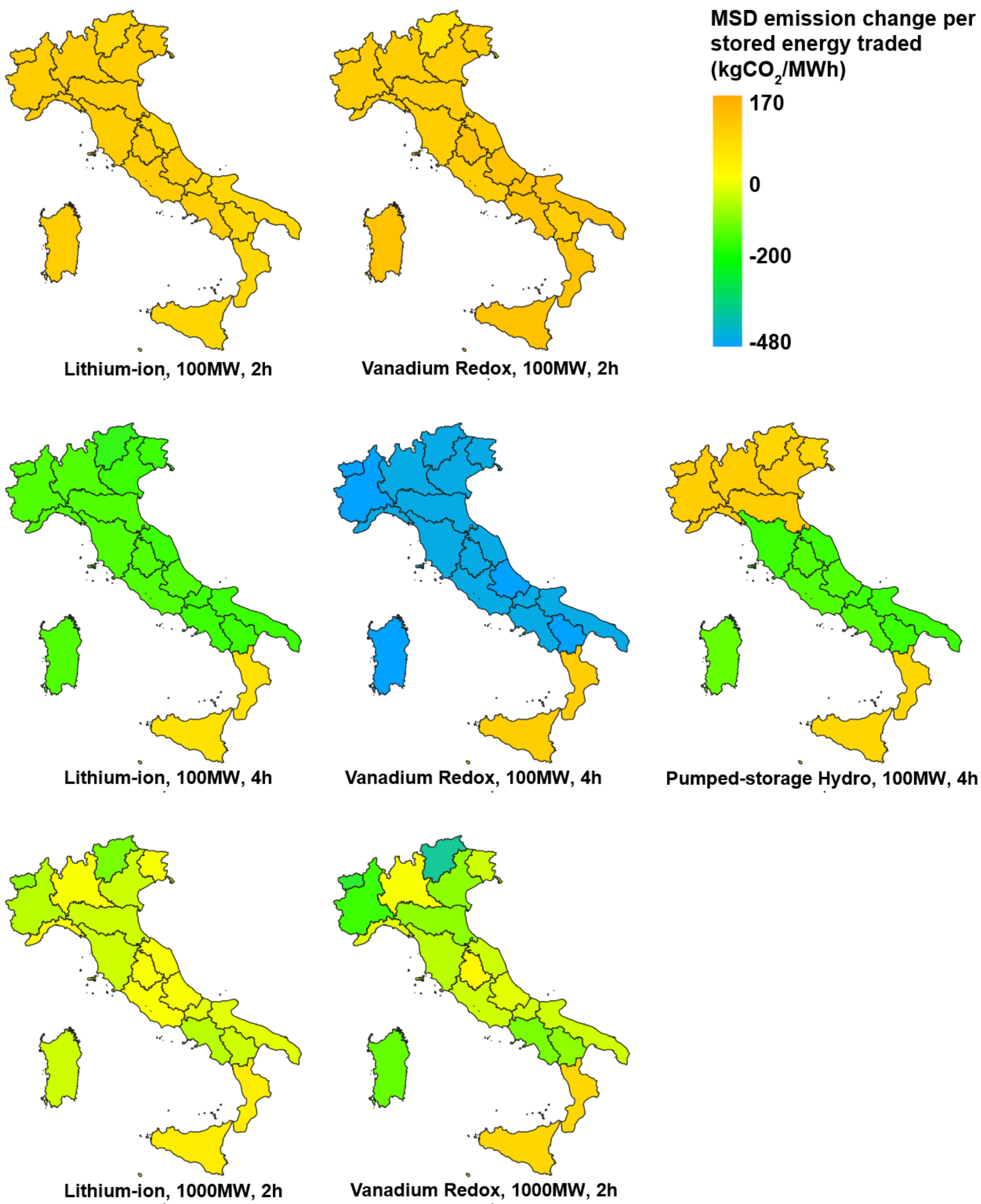

Figure 10 Carbon emission change in the MSD market due to the introduction of a storage device.

5. Conclusion and policy implications

Reaching net-zero carbon emissions by 2050 requires the deployment of a significant amount of large-scale energy storage system, and this can have a significant impact on electricity markets. In this work, we investigated how storage technology, location, rated power, and duration can affect both 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 is used by the transmission system operator to solve network congestion, procure reserve, and offset energy imbalances. A high-fidelity model of the Italian transmission network consisting of more than 1800 nodes has also been developed.

The results show that social welfare and carbon emissions can be significantly affected by large-scale energy storage systems. 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, given the current energy mix. Location, technology, rated power, and duration can have a significant impact on grid carbon emissions change, which can vary 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 can be explained by the relatively high bidding price of solar and wind power plants (greater 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 is expected to decline as wind and solar penetration increases. Given current storage investment costs, and considering the daily time horizon of both the day-ahead and ancillary services markets, the most beneficial asset in terms of social welfare increase and carbon emission reduction appears to be a lithium-ion battery with 100 MW rated power and a four-hour duration. Note, however, that future scenarios may significantly diverge from today's investment cost trends, and storage technologies that are currently at a disadvantage with respect to lithium-ion batteries might become more competitive, e.g. due to 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 both 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. In addition, to support a more holistic integration of LESS, regulators should also design a more comprehensive policy framework that includes market design adjustments, regulatory changes, and coordinated infrastructure investments to support the seamless integration of LESS into the energy system. They 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 at mitigating potential spillover effects and minimising unintended consequences on costs and emissions. This includes accounting for this effect in the TSO's Bidding Zone Review process (EntsoE, 2023a), as well as designing specific strategies and mechanisms for co-optimizing 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) developing a dynamic model to account for future changes in the energy mix, such as increased penetration of renewables; (ii) introducing additional ancillary services, such as frequency response; (iii) widening the considered time horizon; and (iv) introducing long-duration technologies, such as compressed air and hydrogen energy storage systems.

CRediT authorship contribution statement

Iacopo Savelli: Conceptualization; Methodology; Data curation; Formal analysis; Software; Writing - Original Draft. **David Howey**: Conceptualization; Writing - review & editing. **Thomas Morstyn**: Conceptualization; Writing - Review & Editing.

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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 Figure 3, Figure 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 Figure 3, with lithium-ion being the most promising technology for short-duration storage.

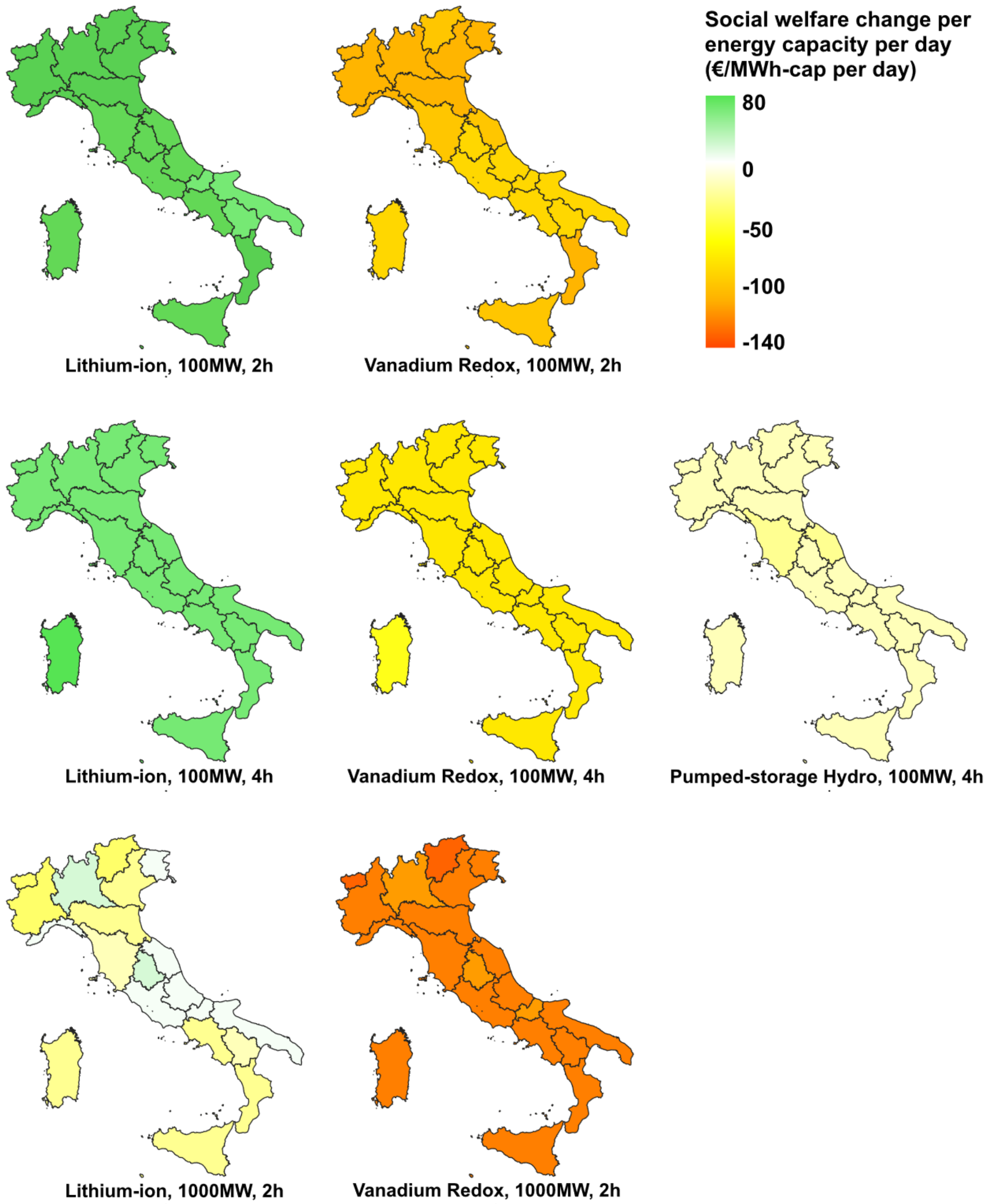

Figure 11 Similarly to Figure 3, this figure shows the social welfare change due to the LESS introduction, but considering a cost reduction for Lithium-ion batteries, Vanadium redox batteries and pumper-storage hydro equal to 20%, 10% and 0%, respectively.

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