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Abstract

The literature highlights ambiguity in the effect of storage from hydroelectric power production over the levels of carbon emissions. This paper examines the external benefit related to charge and discharge operations of hydroelectric storage power plants, applied to the case of the Northern area of the Italian wholesale electricity market. The OLS estimations based on data for year 2018 indicate that storage generation reduces carbon emissions in aggregate terms, being the estimated storage marginal emission factor (MEF) equal to 0.13 tCO_2/MWh. This finding is largely explained by the value of the MEF during off-peak hours (0.17 tCO_2/MWh), thus showing effectiveness of storage in the displacement of the carbon-intensive baseload generation acting on the margin during night-hours. However, the calculation of the MEF for peak-demand hours indicates that storage generation, individually taken, is not able to affect the structure of marginal generation in the considered area. Finally, the use of a simulation approach indicates that pumped hydroelectric storage (PHS) contributed to reduce carbon emissions into the atmosphere by 471 ktCO_2. The obtained result is consistent with the typical coefficient of round-trip efficiency of PHS documented in the literature, which amounts to 74%.

Keywords: *CO_2 emissions; electricity market; Renewable Energy Sources; storage*

JEL Codes: C63; P18; Q41; Q42; Q51

1 Introduction

The process of decarbonising the economy by promoting the penetration of *Renewable Energy Sources* (RES) into the grid requires correct methods to assess the economic and environmental costs and benefits arising from the diffusion of these technologies for power generation. The specific features of RES[1] - which are called to progressively substitute conventional sources for electricity

[1] In this article RES are referred as renewable energy sources including bioenergies (biomass, biogas and waste), hydroelectric, photovoltaic, geothermic and eolic. This group can be further divided into programmable (such as hydropower) and non-programmable (such as wind and solar) renewable energy sources.

generation - makes the evaluation process even more critical.
On top of this, the recent outbreak of COVID-19 pandemic has attracted more attention from policy makers[2] and investors in the attempt of implementing the energy transition that would help meeting the targets set for 2030 in terms of carbon abatement, RES penetration rate and energy efficiency. Given the current reduced fiscal space of policy makers - whose priority is to control the negative socio-economic effects brought up by the emergency - there is an increasing risk that the investments in green technologies might be postponed. In spite of this global emergency, it is becoming crucial to drive the energy transition towards innovative and efficient technology solutions. In this perspective, it is foundamental to progressively invest in batteries and storage systems which allow to benefit from the increasing penetration of clean and cheap electricity from RES power plants (Terna, 2019).

Clearly, the analysis of costs and potential benefits connected to the adoption of forms of energy storage technologies does represent an important research opportunity. At first, the perception might be that the flow of benefits generated by the initial investment and the following operative costs might not be sufficiently high to undertake the decision of installing an energy storage facility.[3] However, Cretì and Fontini (2019) argue that the unbalanced penetration of intermittent RES technologies into the grids leads to increased risks of network congestions, reserve requirements due to their uncertain production and correspondent reduced reserve margins available for baseload conventional power plants. This generates several system costs such as balancing, grid-related and adequacy costs to accomodate the integration of intermittent generation from variable renewable electricity sources (VRES).[4]

Energy storage is largely recognised as a valid mean to mediate between variable RES production and variable loads. With the possibility of arbitrage, energy storage facilities can store energy during off-peak (low-priced) periods and sell it during peak (high-priced) periods on the same market. Similarly, energy storage can be used to "shift" or delay the demand for energy, typically by several hours (*demand shifting* and *peak shaving*) in order to control the events of overgeneration from intermittent RES.[5] Such shifting can be directly used to reduce ("shave") peak demand, which can reduce the total generation capacity required.
In their cross-country analysis of storage diffusion, Estanqueiro et al. (2012) stressed the importance of the interconnection between Portugal and Spain.[6] The installation of *pumped hydroelectric storage* (PHS) plants in Portugal helped simplifying the management of extra-wind generation from Spain and allowed each country to share the generated extra-power with the neighboring partner, thus reducing the electricity price volatility.

[2]With the *European Green Deal Investment Plan* (EGDIP), or *European Green Deal*, the European Commission mobilises at least €1 trillion in sustainable investments over the next decade. As part of the Plan, The Just Transition Mechanism (JTM) activates €100 billions of investments for the period 2021-2027 to support member States in the transition towards a low-carbon sustainable economy.

[3]This is the so called "missing market" problem described by Newbery (2016).

[4]For a recent analysis on the effect of the negative demand shock due to the Covid-19 lockdown - a situation that the authors argue as conceptually equal to a higher infeed from RES - on real-time re-dispatch costs in Italy, see Graf et al. (2021).

[5]This is referred as the *energy-intensive* service of storage units, which enables to handle the structural overgeneration from RES and network congestions. This is compatible with the other service, i.e. the *power-intensive* service, which is characterised by very fast reaction times (seconds/minutes) and guarantees the system inertia (Terna, 2019).

[6]At the time of their study, the only interconnection between Portugal and Spain accounted for a capacity of nearly 1.3 GW. The similarity between the two countries was that in 2010 almost 16% of energy consumption was fulfilled by wind power. Given such high penetration, there was significant excess of supply from wind. Therefore, the curtailment of part of the wind resource was rather frequently imposed.

Nevertheless, some costs emerge when substituting peak-load generation with energy storage capacity. As pointed out by Geske and Green (2020), there may be some times in which it becomes optimal to limit the discharging process or even execute the charging process at times of high prices. This is referred by the authors as "*precautionary storage*", because it reduces the risk of outages caused by unpredicted events of high peak demand and unexpected low RES generation, which cannot be addressed by the constrained discharging capacity of hydrostorage facilities. This strategy of withholding some energy to prevent potential load-shedding occurrences needs to be evaluated when running short-term operations and, more generally, for the overall feasibility of investments in storage.
All in all, the presence of energy storage facilities can simplify the dispatching strategies of the *Transmission System Operator* (TSO). In this regard, energy storage can add more power quality and reliability, together with improved transmission and distribution solutions to mantain balance between the demand and supply (*frequency regulation*).[7] However, the assessment of the near-term effects of energy storage on greenhouse gas emissions when high penetration of variable renewables is involved are still uncertain (Pimm et al., 2021).

This article assesses the short-term effects of hydrostorage on carbon emissions. The analysis is applied to the case of the Italian day-ahead (DA) electricity market which, for its configuration, has been explored by many authors (Clò et al., 2015; Sapio, 2015; Graf et al., 2020) for its high level of data transparency,[8] its peculiar market configuration in the context of zonal pricing[9] and the wide penetration of RES being increasingly relevant as marginal units of power generation.
On one hand, this study introduces an OLS model with fixed effects to calculate the environmental benefit connected to generation from hydrostorage. Hourly data for year 2018 on carbon emissions and storage generation are collected, together with control variables such as electricity load, electricity generation from intermittent RES (small and large scale wind and solar power plants) and equilibrium zonal prices. This full dataset allows to assess the extent to which the generation from hydrostorage affects the levels of carbon emissions from electricity production in the whole grid, with specific considerations regarding differences between peak and off-peak hours of power demand that are relevant due to the evidence of arbitrage.
On top of this, the simulation methodology by Beltrami et al. (2021) is used to obtain a novel calculation of the net balance of reduced carbon emissions connected to the operations of PHS plants. In particular, the comparison between the amount of carbon emissions savings from PHS generation and the extra CO_2 emitted for the provision of power to recharge PHS plants enables to obtain a measure of the net amount of saved carbon emissions from PHS charge and discharge operations for the entire grid.
The study is performed on the same dataset generated by Beltrami et al. (2021). Due to the pre-

[7]As concerns Italy, the PNIEC plan (*Piano Nazionale Integrato Energia e Clima*) (Ministero dello Sviluppo Economico, 2019) promotes the installation of additional strategic Utility-Scale accumulation capacity of at least 6 GW within 2030, with specific efforts in the Southern regions - where the penetration of RES is more significant and storage capacity is still limited - with the primary aim of reducing the risk of congestions. At the moment 22 PHS power plants are active in Italy, with a total installed capacity of 6.5 GW for accumulation and 7.6 GW for production.

[8]Public domain bids/offers data submitted by market participants are available on the website of the GME (*Gestore del mercato elettrico*), the Italian Independent Market Operator.

[9]The Italian MGP is a zonal market, divided in six physical market zones: North, Center North, Center South, South, Sicily and Sardinia. Each market zone generates its own supply and demand curves for each hour of the day. Producers receive the zonal market clearing price, while consumers pay the weighted average of zonal prices, called PUN (Prezzo Unico Nazionale - *Single National Price*).

dominant diffusion of hydroelectric power plants in the North zone of Italy, only the results for this physical zone are carefully examined.

This article is organised as follows. Section 2 provides a broad classification of energy storage technologies and reviews the existing literature on PHS in electricity markets. Section 3 introduces the methodology for the calculation of the environmental benefit related to hydrostorage and the net balance of carbon emissions connected to PHS operations. Section 4 describes the dataset used for the analysis. Section 5 reports the main results. Section 6 concludes with final remarks.

2 Literature review

2.1 Classification and diffusion of storage units

The literature on the aggregate economic and environmental effects caused by the installation of storage power plants in electric grids is quite limited. Given the relatively low diffusion of storage facilities in general, still most of the studies are focused on the technological integration of storage with RES units of power generation.

The high installation costs of storage mainly explain the heterogeneity of the commercial diffusion of energy storage technologies, as displayed by Figure 1. PHS and Compressed Air Energy Storage (CAES) are the most mature technologies, whereas the others still incorporate a cost and risk premium which reduce their applicability.

As reported by Denholm and Sioshansi (2009) and Lund et al. (2009), the most relevant form of storage after PHS is CAES.[10] At the moment of the present study, CAES technology is very poorly diffused in the systems. Only two plants are currently operative: one in Huntorf (390 MW), Germany and the other in McIntosh (110 MW), USA. According to Denholm and Sioshansi (2009), the decision of locating CAES facilities in a load-sited or a wind-sited position is critical. The authors found that, in the U.S., co-locating wind with storage facilities decreases transmission costs but also decreases the economic value of energy storage compared to locating it at the load center. Geography, accessibility, economics and correlation with RES generation are important factors to take into account to evaluate the suitability of the sites for CAES (Succar and Williams, 2008).

As concerns the classification of energy storage technologies, the World Energy Council (2016) distinguishes them by identifying the form in which the energy is stored. The five categories are the following: mechanical (PHS, CAES, LAES, flywheels), thermal (thermo-chemical, sensible-thermal, latent-thermal), chemical (hydrogen storage, synthetic natural gas), electro-chemical (lithium-ion battery, lead acid battery, sodium-solphur battery, redox flow battery) and electrical storage systems (supercapacitors). These technologies are characterised by different degrees of energy and power intensity.

Beyond this scientific classification, there is a list of technical factors affecting the overall configuration of single energy storage technologies and their value. The definition of the key performance characteristics, the storage duration and the maturity eventually introduce further classification options. These extensions are explored in the next sub-section with a specific emphasis on the

[10]CAES is a slight modification of gas turbine (GT) technology, where energy is stored by compressing air in an underground cavern at off-peak hours. Then, during peak hours, the compressed air is extracted from the storage vessel, heated and expanded through a high-pressure gas turbine. Finally, air is mixed with fuel (natural gas) and combusted through a low-pressure gas turbine. Ultimately, the turbines are connected to a generator which produces electricity for the grid.

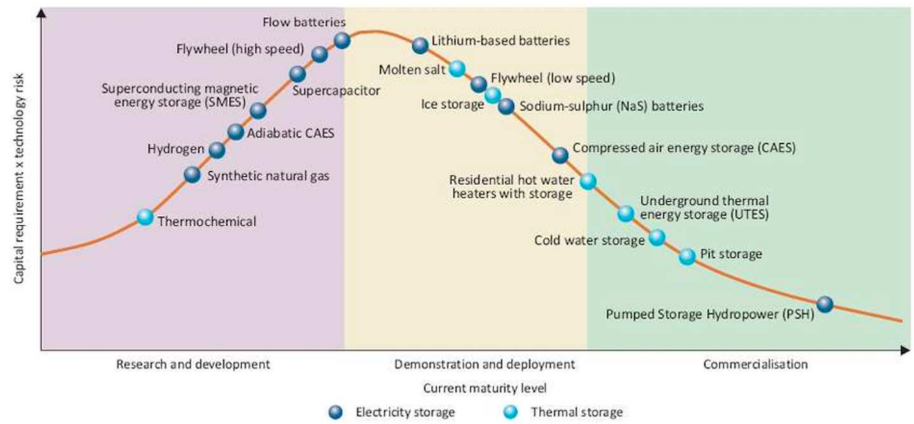

Figure 1: *Diffusion of energy storage technologies, distinguished between electric and thermal storage application. Source: World Energy Council (2016).*

opportunity of arbitrage for economic agents.

2.2 Key parameters in electricity storage

In this sub-section the main technical parameters of energy storage technologies and their connection with the evaluation of potential arbitrage opportunities are considered. The following list is an elaboration which builds up on the insights included in Beaudin et al. (2010), Sioshansi et al. (2009) and World Energy Council (2016). For sake of simplicity, it is assumed that there is perfect ability to foresee the evolution of hourly energy prices across time.

- Installed power capacity (MW). This represents the size of a storage facility, which has to face some fixed and variable costs whose magnitudes are linked with efficiency. As reported by Sioshansi et al. (2009), usually intra-day arbitrage (for moderate facility size) conveys the largest part of the value of arbitrage from storage, since the first 4 hours of storage enable to extract nearly 50% of the maximum theoretical gain from arbitraging. Longer-term storage (with increased facility size) can extract further arbitrage value thanks to the inter-day arbitrage, especially by recharging during weekends (when prices are tipically lower than weekdays) and discharging during the following week.

- Rated energy capacity (MWh). It is by convention the discharge capacity, or the energy capacity rated by the number of hours at full power output. As described by Sioshansi et al. (2009), usually small batteries and flywheels have rated energy capacities of less than one hour which make them suitable for higher power applications. Conversely, large PHS or CAES facilities can reliably meet a full day's 8 peak demand period.

- Discharge time.[11] It can be: (1) "seconds to minutes" in case of short-term energy storage systems (supercapacitors and flywheels) with E2P ratio equal to 0.25 hours; (2) "daily"

[11]The discharge time (or discharge duration) is technically defined E2P, i.e. Energy to Power ratio. It is the number of hours for the device to release its output energy.

medium-term energy storage systems (PHS, CAES, LAES, batteries, thermochemical redox flow) with E2P ratio ranging between 1 and 10 hours; (3) "weekly to monthly", or long-term energy storage systems (sensible/latent thermal PtG) with E2P ratio between 50 and 500 hours.

- Roundtrip efficiency (%). It is the ratio between the discharge time and the required amount of charging storage time.[12] For example, a 50%-efficient device is able to supply 1 hour of discharge, given a required storage time of 2 hours, whereas a 80%-efficient device (nearly the efficiency of modern PHS) is able to supply 1 hour of discharge given a required storage time of only 1.25 hours. It then becomes crucial to relate this indicator to the potential value of arbitrage from storage. As determined by Sioshansi et al. (2009), efficiency is positively correlated with the value of arbitrage. This is due to the fact that, given the same amount of storage capacity between two devices, the inefficient device needs more hours to be recharged and these added hours are tipically more expensive, thus reducing the potential gain from arbitraging.

- Ramp rate (or response time). By taking the PHS facility as example, it represents the amount of water flow per fraction of time (MW/s). The ramp-up rate is the situation in which there is an increase in the ramp rate due to the release of energy (generation) to the grid, typically during hours of high demand and prices. Conversely, the ramp-down is the accumulation of energy in the reservoir typically during low demand and prices.
  Intuitively, at very high penetration of VRES, it is more convenient to have high ramp rates to be able to quickly react to the increased infeed from intermittent renewables. However, as suggested by Niu and Insley (2013), the public authority might consider to impose ramping restrictions to the hydro facility in order to mantain the overall ecosystem stability. Clearly, there are several potential environmental issues and economic trade-offs connected to these restrictions: they might de facto (1) reduce the profitability of running the hydro facility, (2) reduce the flexibility of modulating its production to meet demand changes and (3) increase potential emissions from more costly generation (such as coal or gas) to substitute the reduced hydro supply.

- Capital capacity cost. This is connected to the specific technology risk and has to do with the technological progress. Despite the significant high capital costs of storage, the experience curve for Lithium-ion batteries suggest that there is reason to believe that economies of scale can actually sustain cost reductions at higher volumes of production once the facility is under normal operations. Beaudin et al. (2010) report that CAES requires $400–800/kW as capital cost, far lower than the high capital cost for PHS ($600–2000/kW).

- Maturity. This indicates the commercial diffusion of the storage technologies and is clearly related to capital capacity cost and risk. Many additional factors can affect the commercial maturity: market incentives, installation volumes, technical constraints and geographical restrictions.

[12] There is a caveat here: the distinction between charge and discharge time is only needed to define the concept of efficiency. As a matter of fact, the charging storage time - or energy storage capacity - is often referred also as discharge time.

2.3 *Pumped hydroelectric storage (PHS)*

The most established bulk electrical energy storage in use is *pumped hydroelectric storage (PHS)* with a global installed capacity around 130 GW (Barbour et al., 2016; Denholm and Sioshansi, 2009), which represents 97% of total storage capacity.[13] This technology can be used for storage purposes behaving like a battery by mainly relying on large reservoirs,[14] in the sense that it stores energy during low-demand off-peak hours by pumping water uphill from a reservoir at lower elevation to a reservoir at higher elevation.[15] Then, it releases this accumulated energy when demand is high or system generation is low.

Technically, both pumps and turbines are connected to the same upper reservoir. However, there are two types of PHS schemes depending on how pump and turbines are connected to the lower reservoir:[16]

- when both pumps and turbines are connected to the same lower reservoir, the pumping cycle can be voluntarily repeated a great number of times in a loop. This type is called "voluntary" PHS. More precisely, depending if the natural supply of water that aliments the upper reservoir is, on average, lower or higher than 5% of the average volume of water turbined during a year, the PHS is defined pure or mixed, respectively.
- when pumps are connected only to the lower reservoir, which is instead separated from the upper reservoir, it is not possible to have infinitely repeated pumping cycles. In this case, the only role of pumps is to pump up water from the lower to the upper reservoir. This type of PHS is called "eaves" PHS.

For its large scale size and diffusion, there is a wide emphasis of the literature in studying the private and social costs and benefits arising from PHS operations within national grids. As highlighted by Olsen and Kirschen (2020), the literature reports mixed evidence about the impact of storage on carbon emissions which depends on several factors: charging and discharging strategies, generation mix, reserve scheduling rules, and the quantity of storage installed. Here is a literature review on the topic.

Primarily, the installation of storage facilities is directly connected to the opportunity of arbitrage due to its natural configuration. By following Sioshansi et al. (2009) in their study on the American PJM from 2002 to 2007, storage allows to take advantage of the differences in electricity prices between off-peak and peak hours. In operative terms, storage plants can buy and accumulate (store) electricity at off-peak hours, when prices are low and the charging process is more convenient, and then sell the stored power by releasing (offering) energy to the grid at peak hours when prices are higher. This has further positive welfare implications, especially in the case of the deployment of this technology on a large-scale basis. Arbitrage can in fact determine a smoothing of the load structure and a reduction of its variability, since there is an increased demand of power at off-peak

[13]Beaudin et al. (2010) report that the reason of this popularity is due to its relatively high efficiency (65-85%), its large power capacity, large storage capacity, and long life (30-60 years) at a low cycle cost.

[14]The size of a PHS can range from 100 to 1000 MW.

[15]PHS is distinguished from diversion (run-of-river) and impoundment reservoirs (large dams) forms of hydroelectric production. This classification is based on the retention time of the cumulative inflow into reservoir, i.e. the required timing for accumulating a volume of water which is sufficient to fulfill its capacity. This retention time is less than 2 hours for run-of-river, it is between 2 and 400 hours (nearly 17 days) for impoundment (modulable reservoirs with a moderate potential for storage) whereas it is greater than 400 hours for PHS (highly flexible and modulable for storage).

[16]This information is taken from the Italian TSO website, Terna.

hours (due to the recharging process of accumulation) and a reduced demand at peak hours when the storage facility is releasing energy to the grid. This also levels out the price variability and guarantees more stability for end users. Additionally, there is a parallel reduction of the risk of congestions.[17] Despite these positive implications, the authors also warn about the corresponding decrease of the value of arbitrage itself through time, which would in turn disincentivise private investments in storage facilities. Eventually, depending on the specific geographic site and the quantities involved, only a careful examination of costs and benefits determines which of the two prevail.

In their study applied to the Texas market, De Sisternes et al. (2016) also document that as storage penetration increases the marginal value of storage decreases through time. Nevertheless, when a strict emissions constraint policy is introduced, the value of energy storage can increase even further. The authors argue that subsidising electricity from storage leads to several benefits in welfare terms. Promoting storage can in fact reduce carbon emissions beyond reducing the costs of integrating RES into the grid; it reduces the required investments needed for nuclear power and gas-fired units; it improves the utilisation of the overall current installed capacity. In terms of private benefit, the economic profitability of a 10-hour storage capacity facility is found to be consistent with the current cost (e.g. PHS) whereas the economic benefits for a 2-hour storage facility is worthy only under strict emissions thresholds.

Linn and Shih (2019) report that the presence of storage actually reduces price differentials across peak and off-peak hours, though it has a rather ambiguous effect on emissions. The latter essentially depends on the price responsiveness of fossil-fueled (natural gas, coal) power plants and RES units of production. For instance, the more reactive the RES investment is to price fluctuations (caused by the introduction of storage) in the positive direction, the more likely a decrease in storage costs can reduce emissions. This is true for wind, whose price is positively correlated with storage price. Viceversa, the more reactive the RES investment (the choice of investing in a storage unit) is to price fluctuations in the opposite way (such as the one in solar panels, whose price is negatively correlated with storage price), the less likely a decrease in storage costs will actually reduce emissions. Additionally, the uncertainty of the final result on storage costs and emissions is amplified when considering the introduction of carbon emissions allowances (carbon price scheme) in the market.

Despite several positive implications from introducing additional storage capacity into electricity grids, there are numerous studies that mainly highlight the negative effects connected to it.

Carson and Novan (2013) explored the role of bulk electricity storage in the Texas electricity market by looking at the social and environmental consequences of arbitraging electricity - through bulk storage - across time. The authors empirically find that for each MWh of electricity stored there is an average increase of 0.19 tons of CO_2 into the environment. However, they recognise that this negative environmental benefit connected to storage was largely dependent on the small amount of intermittent RES generation in the Texas market. At the time of the study, their share in the total generation mix was accounting for less than 8%.

A similar result is found by Nyamdash et al. (2010), who studied the implications from combining wind and large scale storage PHS facilities in the Irish power system. They report that this integration actually reduced the participation of mid-merit power plants and raised the one of base-load power plants in the market. On top of this, the participation of storage power plants lowers the potential carbon offset obtainable by wind generation itself, given a range of different scenarios which differentiate the possible intensities of wind penetration into the grid.

[17]See Gianfreda and Grossi (2012) for more insights about congestion management.

Sioshansi (2011) showed the negative consequences on the levels of carbon emissions in the Texas electricity system when accounting for market power. Firstly, it is reported that the introduction of storage has a greater impact on the increase of carbon emissions, when it is combined with additional wind capacity, than when storage alone is added into the system. Secondly, market power exacerbates this negative effect. As a matter of fact, the more polluting coal-fired capacity could be intentionally withheld from the market, thus leaving wind to displace gas-fired generators that actually have a lower carbon intensity. Eventually, the actual carbon saving might be lower than the potential carbon reduction under no market power.
The potential value of electricity storage arising from intra-day arbitrage operations within the British wholesale electricity context is analysed by Giulietti et al. (2018). The authors focus on the private costs and benefits to evaluate the commercial benefits of a small-size price taking CAES technology facility, whose technical parameters are the ones derived by Lund et al. (2009). Under several hypothetical efficiency values and actual price differentials across peak and off-peak hours, the optimal timing for a profitable storage and release strategy is found to be approximately 2 hours. Given this strict timing, the potential gains from arbitrage become considerably low, unless the storage facility is properly integrated with a wind turbine, in order to counterbalance for the unpredictability of its supply.
The long-term effects of storage facilities in terms of carbon mitigating policies are explored by McPherson et al. (2018). The authors utilise an integrated assessment model to verify the diffusion of large-scale variable renewable energy (VRE) resulting from the introduction of electricity storage and hydrogen technologies, including utility-scale batteries, PHS, CAES and hydrogen electrolysis. This assessment model is calibrated depending on a range of optimistic and pessimistic assumptions about the technical efficiency of storage technologies.

3 Research methodology

3.1 Econometric model

To assess the average environmental benefit related to increasing levels of power generated from storage facilities, the identification strategy suggested by Hawkes (2010) with regard to the calculation of the *Marginal Emission Factor* (MEF) from electricity production is adopted.[18] Thus, the amount of hourly carbon emissions ($E_{h,z}$) is regressed over the hourly accepted generation from storage power plants ($S_{h,z}$). In this case, the generation from hydrostorage not only includes pure PHS units, but also the larger group of units represented by modulable hydroelectric power plants.

$$E_{h,z} = \beta_0 + \beta_1 S_{h,z} + \epsilon_{h,z} \tag{1}$$

The estimated β_1 coefficient represents the marginal CO_2 effect arising from a 1 MWh increase of hydrostorage generation.
To avoid the issue of omission of regressors, additional explanatory variables are added to the specification. The first control is the hourly generation from intermittent RES ($intRES_{h,z}$), that controls for the effects of variations from large and small-scale wind and solar facilities, for which it is assumed that their generation have no carbon impact into the environment. Their production is exogenous, since it depends on weather conditions only. Thus, the inclusion of this variable allows

[18] For a complete review of the estimation methods of $MEFs$ from electricity production, please refer to Beltrami et al. (2020).

to measure the effect of switching between thermoelectric polluting generators and intermittent RES generation on carbon emissions.[19] A second potential source of variability is represented by the variations related to electricity demand (or load) in the grid.[20] Thus, the second control is the amount of hourly net load, $netload_{h,z}$, i.e. the total load at the net of the demand coming from PHS units.[21].

Equation (2) formalises the main relationship object of investigation.[22]

$$E_{h,z} = \beta_0 + \beta_1 S_{h,z} + \beta_2 intRES_{h,z} + \beta_3 netload_{h,z} + \gamma_4 D_{h,z} + \epsilon_{h,z} \tag{2}$$

In particular, $intRES_{h,z}$ is the hourly generation from intermittent RES (large and small-scale wind and solar); $netload_{h,z}$ is the net hourly demand of electricity from the grid; $D_{h,z}$ is a set of dummies that control for hourly and day-of-week fixed effects.

On top of this, it is crucial to incorporate the distinction between relevant periods in the analysis. As reported above, the production of hydroelectric storage facilities can be modulated across hours. Specifically, these units tend to recharge during off-peak hours and discharge during peak hours, by releasing the accumulated power into the grid. Thus, to separately investigate the estimated coefficients, two different sub-samples are distinguished.

Equation (3) specifies the distinction between peak and off-peak hours. The subscript *peak* activates at 1 if the variables are observed at peak hours (i.e. from 8 a.m. to 8 p.m.) and remains at 0 for off-peak hours (from 1 a.m. to 7 a.m. and from 9 p.m. to 12 p.m.).

$$E_{h,z,peak} = \beta_0 + \beta_1 S_{h,z,peak} + \beta_2 intRES_{h,z,peak} + \beta_3 netload_{h,z,peak} + \gamma_4 D_{h,z,peak} + \epsilon_{h,z,peak} \tag{3}$$

In Equation (3), β_1 represents the marginal emission factor from storage generation at peak hours. This can be directly compared with the estimations obtained from the specification for off-peak hours. The coefficient β_2 represents the marginal effect of additional intermittent RES generation on the levels of CO_2 emissions at peak hours of production (generally PV).

In their analysis on the Texas electricity market, Carson and Novan (2013) find that the off-peak MEF from storage generation is higher than the correspondent peak MEF. This is due to the merit-order dynamics and, in particular, to the efficiency of thermoelectric power plants acting as marginal generators in the observed sample. As a matter of fact, the request of electricity from PHS units during off-peak hours raises the overall demand to be met by baseload generators. During off-peak hours, this excess of demand is generally met by thermoelectric power plants which are relatively more inefficient and are characterised by higher carbon intensity with respect to the units operating at the margin during peak hours.

[19] This effect is similar to the one studied by Graf and Marcantonini (2017), who measured the effect of additional intermittent renewable production on the emission factors of thermal power plants for the Italian electric grid.

[20] As stated by Clò et al. (2015), the consumption of electricity is mainly price insensitive and inelastic due to the cyclical request of power from the grid. Thus, the inclusion of this component assures exogeneity in the model.

[21] Usually, PHS units buy power from the market during off-peak hours, causing an increase in the level of total demand and eventually an increase in the levels of emissions. This step is crucial to identify β_1 in Equation (2) as the marginal emission reduction from a unitary increase in electricity generated by storage power plants, net of the increased emissions produced by the consumption of electricity of PHS units for their accumulation of energy.

[22] Note that, in the notation by Beltrami et al. (2020), the methodology for the estimation of MEF in Equation (2) is the "US fixed-effects" approach.

3.2 Simulating the effect of PHS

This sub-section presents the simulation approach for the calculation of the net amount of saved carbon emissions from charge and discharge operations of PHS units.

The analysis stems from the construction of counterfactual scenarios which simulate the impact of PHS units on the market equilibrium in each observed settlement period. By starting from the status-quo scenario S^* that replicates the occurred ex-post market equibrium, the counterfactual scenarios S is built under the assumption that the PHS units did not place neither demand nor supply bids in the market. This methodology is applied to identify the net amount of carbon emissions due to charge and discharge operations of PHS power plants.[23]

As argued by Staffell (2017), "pumped hydro storage does not create CO_2 emissions by itself; however, the electricity it stores is not carbon-free, and it only redelivers this electricity with 73.6% round-trip efficiency [...]". Moreover, "with round-trip losses, these plants deliver electricity with a carbon intensity 31±9% above the system average [...]. Here these emissions are accounted for when the electricity was first generated, and are attributed to the technologies which produce that electricity". McKenna et al. (2017) indicate that "the overall storage emissions factor is dependent on the marginal emissions factors during charging and discharging, and the storage round-trip efficiency".[24]

In this paper, the identification of the amount of net carbon emissions due to charge and discharge operations of PHS power plants is based on two quantities. The first quantity, formalised in Equation (4), represents the amount of carbon emissions produced during the charging process of PHS power plants. The request of electricity from PHS plants typically takes place during off-peak hours and needs to be fulfilled by other power generators, thus increasing potential carbon emissions. To simulate the effect of the demand from PHS on the levels of emissions, it is assumed that the demand curve is shifted under the scenario $S = PHS$ of omitting the demand bids from PHS plants in the market. This results in the creation of a new type of counterfactual equilibrium, which is characterised by lower quantities, lower price and less emissions.

Therefore, by slightly adjusting the notation by Beltrami et al. (2021), the extra CO_2 produced due to charging operations of PHS is given by:

$$\Delta E^P = E^* - E^{scenario,D} \tag{4}$$

Where E^* is the amount of emissions under the status-quo scenario. $E^{scenario,D}$ is the assumed amount of CO_2 emitted under the counterfactual scenario for which the demand is reduced, since the demand bids from PHS units are artificially removed from the actual demand curve. Hence, given the constraint $E^* \geq E^{scenario,D}$, ΔE^P is a non-negative quantity, and represents a negative externality of the actual carbon releases occurred to serve the demand coming from the charging process of PHS plants.

The second quantity is formalised in Equation (5). This represents the amount of CO_2 saved due to discharging operations of PHS.

$$\Delta E^S = E^{scenario,S} - E^* \tag{5}$$

[23] For a complete description of the simulation methodology aimed at assessing the economic and environmental impact of RES within the Italian day-ahead power market, please refer to Beltrami et al. (2021). The approach is similar to the one adopted by Espinosa and Pizarro-Irizar (2018), who rely on the identification of multiple simulation scenarios for the analysis of the Spanish electricity market.

[24] This is formalised by McKenna et al. (2017) with the following equation: $\epsilon_{storage} = \epsilon_{charge} - \epsilon_{discharge}\eta_{storage}$ where the letter ϵ stands for emission factor and η for the assumed round-trip efficiency.

Where E^* is the amount of emissions under the status-quo scenario and $E^{scenario,S}$ is the amount of emissions that would happen under the scenario $S = PHS$ of removing the supply bids of PHS from the actual supply curve. In this second case, the reasoning is opposite to the one used to model Equation (4). The constraint is now given by $E^{scenario,S} \geq E^*$ and ΔE^S is a non-negative quantity which represents a positive (unobservable) externality, i.e. the amount of CO_2 emissions avoided from PHS generation.
Thus, the difference between Equation (5) and Equation (4) produces the net environmental benefit from charge and discharge operations of PHS power plants.[25]

$$\Delta E_{PHS} = \Delta E^S - \Delta E^P \tag{6}$$

The value obtained in Equation (6) accounts for the losses connected to the operations of PHS units. As indicated by Staffell (2017), the coefficient of round-trip efficiency related to PHS power plants is nearly 73.6%.

4 Dataset

This Section describes the database used for the empirical analysis. The main source of information is the list of public offers (in Italian *Offerte Pubbliche*) provided by the GME - *Gestore del Mercato Elettrico*, the independent market operator - which allows to obtain the full list of electricity supply and demand bids submitted on the day-ahead power market (*Mercato del Giorno Prima*, MGP), the marketplace where producers and buyers exchange power in Italy.
Due to high data availability and the large diffusion of hydroelectric power plants, the analysis is restricted to the physical zone North. The four variables used in the econometric analysis are described here. Additionally, the information regarding the zonal market price is reported. The entire dataset is based on hourly-frequency data for year 2018.[26]

1. Carbon emissions (tCO_2).[27] Data on carbon emissions related to plant-level power production are constructed from a preliminary technical encoding of thermoelectric units of generation. The collection of data on plant-level efficiency coefficients and average national carbon intensities from local fuel combustion allowed to estimate the amount of fuel required by thermoelectric units at the hourly basis. The empirical fuel consumption model for the calculation of plant-level carbon emissions is fully described in the Appendix.

2. Hydrostorage generation (MWh). Data on generation from storage are obtained by filtering the sequence of accepted supply bids arising both from pumped hydroelectric storage (PHS)

[25] Note that all the simulations are referred to the hourly market equilibria occurred in 2018 and only then aggregated at the annual level. Crucially, the more specific cases of single hours for which both demand and supply bids were simultaneously placed by PHS power plants is included in the simulating algorithm.

[26] Year 2018 has been chosen as a representative year as evidenced by some key indicators (electricity consumption, generation level and fuel mix, and plant position in the merit-order) obtained from the reports by TERNA and ARERA (*Autoritá di regolazione Energia Reti e Ambiente* - the Italian regulatory authority for energy, network and the environment). Moreover, the most recent year 2020 is not suitable for the analysis, due to the structural change in generation and demand patterns caused by the Covid-19 pandemic.

[27] According to Tranberg et al. (2019), there are two approaches for carbon accounting. One is consumption-based, while the other is production-based. In this work, the production-based accounting method is exploited.

and modulable large water reservoirs. Crucially, PHS plants represents only a small subset of storage units, which is composed by both PHS units and modulable hydroelectric power plants.[28] As regards the North market zone, the ratio between the accepted supply from PHS and the total accepted supply from storage was 10.87% in 2018.
Furthermore, only a fraction of PHS units did operate as buyers in the market in 2018. To identify them, a preliminary matching of demand and supply bids was performed.[29] The result of this preliminary matching of PHS plants is reported in Table A.4 in the Appendix.

3. Intermittent RES generation (MWh). Data on generation from intermittent RES sources are obtained by extracting the sequence of hourly accepted supply bids arising from (1) PV units, (2) wind turbines and (3) Non-Relevant RES (NRRES) units of production.[30]

4. Net load (MWh). The information about the accepted electricity demand on the MGP is provided by the GME. The calculation of net load is identified as the amount of total load, at the net of the demand arising from PHS units.[31]

5. Zonal market price (€/MWh). The information about the equilibrium zonal market price awarded by the suppliers is available on the GME website. Noteworthily, the GME specifies that for the mixed type of supply points (i.e. pumping units) the zonal market price is applied both to supply and demand bids.[32]

Table A.2 reports the descriptive statistics of the variables used for the econometric estimations. Table A.3 disentangles the descriptive statistics by off-peak and peak hours.
As regards data representativeness, Table A.4 reports an overview of total PHS capacity in Italy at the end of 2018 by each physical zone. Besides, it indicates whether in 2018 the PHS unit placed both supply and demand bids in the MGP market. As shown in bold, the investigation led to detect 5 units for North and 2 for Center South. This information is used for the calculation of the hourly net load, i.e. the hourly total load at the net of the accepted demand from PHS units.
Figure 2 displays the behaviour of raw time-series variables in 2018 collected for the market zone North. Data are characterised by low-scale seasonality patterns (daily and weekly), which are better visible in Figure 3, where the detail of the last two weeks of March 2018 is provided. Remarkably, data seem to indicate that the daily peak of production from intermittent RES (mainly PV) is connected to a relative minimum in CO_2 emissions. Besides, the data show a first drop of load and generation which is related to midday break. After that, the levels of carbon emissions (and similarly load and generation) reach a second daily peak occurring at 7 p.m.

[28] In this stage, the production from hydro-of-river and poundage facilities is omitted, due to their scarce applicability for storage purposes and its relatively low modulation potential.

[29] The GME defines the pumping units as a mixed type of supply point, since they place both supply and demand bids for electricity. They are defined as *mixed units of production and consumption*. They are distinguished from the standard supply points which only place supply bids in the MGP.

[30] *Non-Relevant RES* (NRRES) include power plants with installed power capacity lower than 10 MW. This category is mainly represented by small-scale solar, wind and small hydro power units.

[31] Note that this variable is different from the value of the *residual load* commonly analysed in the literature, i.e. the total load at the net of production from RES.

[32] The GME specifies that pumping units do not contribute to the determination of the Single National Price (*Prezzo Unico Nazionale, PUN*), which is the final price applied to buyers of electricity.

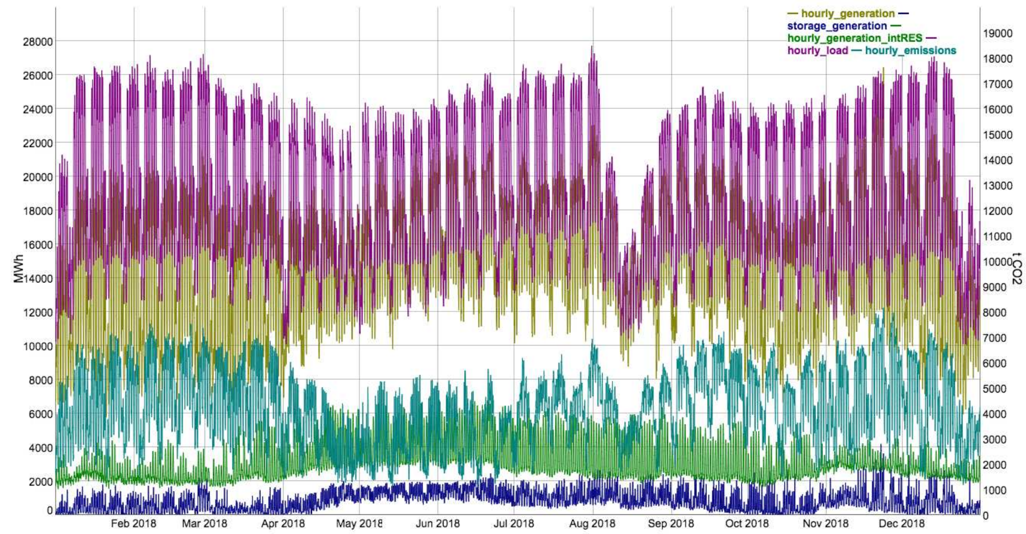

Figure 2: *Time series data for the zone North in 2018. Note that hourly carbon emissions (light blue) are measured on the secondary vertical axis. Source: own elaboration.*

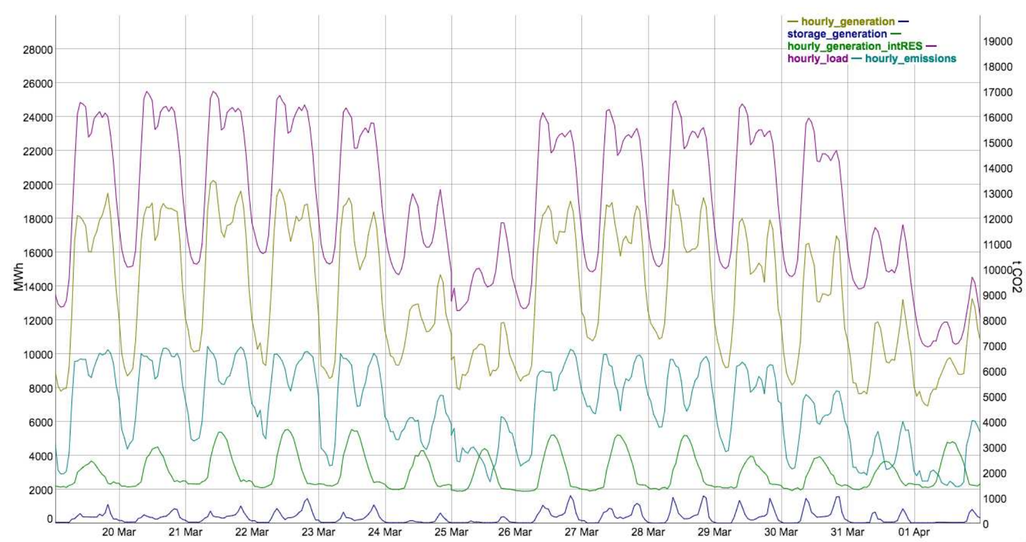

Figure 3: *Time series data for the last two weeks of March 2018 for the zone North. Note that hourly carbon emissions (light blue) are measured on the secondary vertical axis. Source: own elaboration.*

5 Results

5.1 The MEF from hydrostorage generation

This Section presents the results derived from the econometric estimations, based on the model introduced in Section 3.1.
For the scope of this investigation, the large definition of modulable hydroelectric power plants is here assumed. Therefore, both the data on large hydro reservoirs and pure PHS are used for the following econometric estimations.[33] Moreover, only the results for the zone North are reported, given the large diffusion of modulable hydroelectric power plants in the area.
Column (4) in Table 1 reports the resulting marginal emission factor (MEF) from hydrostorage generation, based on the specification of Equation (2). Similarly, columns (4) of Tables 2 and 3 report the results by subsetting data for off-peak and peak hours, respectively.

The results for the full sample show that generation from storage is found to have a decreasing effect on carbon emissions. When fixed effects are included, the storage marginal emission factor is equal to 0.13 $tCO2/MWh$. This evidence is opposite to the one reported by Carson and Novan (2013), who documented that storage generation has an adverse impact on carbon emissions in the Texas electricity market, reporting that each MWh of electricity stored causes an average increase of 0.19 tons of CO_2 into the environment.[34] Arguably, the result shown in Table 1 may suggest that there is a sufficiently high level of integration between RES and hydroelectric storage in the zone North within the Italian power system.
The magnitude of the MEF from storage can be further investigated by disentangling data for off-peak and peak hours. The calculated storage marginal emission factor during off-peak hours amounts to 0.17 tCO_2/MWh and is statistically significant at the 1% significance level. Conversely, an opposite result is found for peak hours, for which the calculated MEF indicates that each MWh of electricity stored causes an average increase of 0.017 $tCO2$ into the air. However, this latter finding does not show any statistical significance at the 10% significance level.[35]
The calculations lead to a twofold consideration. On one hand, arbitraging electricity by storing power during off-peak hours and releasing it during peak hours does not convey any marginal benefit to the environment. This seems to indicate that, during the periods of highest production and request of power from the grid, generation from storage is still ineffective in crowding-out the carbon-intensive generation from thermoelectric power plants in the system. On the other hand, the estimation of the off-peak MEF from storage is significant and shows that, during night-hours, there is potential for hydroelectric storage power plants to effectively displace baseload carbon-intensive generators, thus reducing the CO_2 emissions arising from the Italian electricity sector.
Finally, the coefficients β_2 and β_3 display the expected signs and are statistically significant, thus showing consistency with the adopted theoretical framework.

[33] The statistical tables are obtained through the package *stargazer* in R developed by Hlavac (2018).

[34] The outcome found by the authors was largely dependent on the time of the study, especially with regard to the low penetration of intermittent RES and the moderate integration of RES with storage capacity.

[35] The econometric estimations reported in Tables 1-2-3 are complemented with a modification of Equation (2), which replaces *net load* with the total *load*, thus including the variations of the energy requests by PHS power plants. This modification allows to identify the MEF as the marginal CO_2 effect when also the cost of buying electricity for PHS power plants is taken into account. Both quantitative and qualitative results are not impacted by this modified version of the estimated model.

Table 1: OLS results for year 2018, full sample. Physical market zone: North.

	Dependent variable:			
	hourly_emissions			
	(1)	(2)	(3)	(4)
storage_generation	0.764***	0.925***	−0.195***	−0.138***
	(0.026)	(0.027)	(0.016)	(0.020)
hourly_generation_intRES		−0.230***	−0.488***	−0.587***
		(0.014)	(0.008)	(0.012)
net_load			0.331***	0.293***
			(0.002)	(0.003)
Constant	3,557.156***	4,144.441***	−347.439***	391.771***
	(25.805)	(44.716)	(37.944)	(64.834)
Observations	8,760	8,760	8,760	8,760
Fixed effects	No	No	No	Yes
R^2	0.091	0.117	0.755	0.767
Adjusted R^2	0.091	0.117	0.755	0.766
Residual Std. Error	1,401.222 (df = 8758)	1,381.331 (df = 8757)	727.656 (df = 8756)	711.025 (df = 8727)
F Statistic	881.139*** (df = 1; 8758)	580.865*** (df = 2; 8757)	8,995.911*** (df = 3; 8756)	897.136*** (df = 32; 8727)

Note: hourly and day-of-week fixed effects. *p<0.1; **p<0.05; ***p<0.01

Table 2: OLS results for year 2018, subsetting for off-peak hours. Physical market zone: North.

	Dependent variable:			
	hourly_emissions			
	(1)	(2)	(3)	(4)
storage_generation	0.422***	1.079***	−0.150***	−0.171***
	(0.036)	(0.044)	(0.030)	(0.033)
hourly_generation_intRES		−1.329***	−0.848***	−0.848***
		(0.058)	(0.035)	(0.036)
net_load			0.372***	0.338***
			(0.004)	(0.007)
Constant	3,402.554***	6,230.764***	−207.469*	395.508***
	(29.498)	(125.826)	(107.142)	(134.393)
Observations	4,015	4,015	4,015	4,015
Fixed effects	No	No	No	Yes
R^2	0.034	0.147	0.693	0.701
Adjusted R^2	0.033	0.146	0.693	0.699
Residual Std. Error	1,223.702 (df = 4013)	1,150.109 (df = 4012)	689.341 (df = 4011)	682.367 (df = 3995)
F Statistic	139.544*** (df = 1; 4013)	344.487*** (df = 2; 4012)	3,024.910*** (df = 3; 4011)	492.608*** (df = 19; 3995)

Note: hourly and day-of-week fixed effects. *p<0.1; **p<0.05; ***p<0.01

Table 3: OLS results for year 2018, subsetting for peak hours. Zone: North.

	Dependent variable:			
	hourly_emissions			
	(1)	(2)	(3)	(4)
storage_generation	0.680***	0.854***	−0.121***	0.017
	(0.037)	(0.035)	(0.021)	(0.027)
hourly_generation_intRES		−0.519***	−0.498***	−0.586***
		(0.017)	(0.009)	(0.013)
net_load			0.301***	0.270***
			(0.003)	(0.004)
Constant	3,950.306***	5,710.707***	278.909***	737.788***
	(42.273)	(68.768)	(64.579)	(84.970)
Observations	4,745	4,745	4,745	4,745
Fixed effects	No	No	No	Yes
R^2	0.065	0.222	0.763	0.773
Adjusted R^2	0.065	0.222	0.763	0.771
Residual Std. Error	1,454.880 (df = 4743)	1,327.368 (df = 4742)	732.919 (df = 4741)	719.277 (df = 4723)
F Statistic	331.372*** (df = 1; 4743)	677.064*** (df = 2; 4742)	5,084.721*** (df = 3; 4741)	763.706*** (df = 21; 4723)
Note: hourly and day-of-week fixed effects.				*p<0.1; **p<0.05; ***p<0.01

5.2 Net carbon balance of PHS

This sub-section computes the net carbon balance from the impact of PHS charge and discharge operations in the market zone North in 2018. The results, based on the arguments included in Section 3.2, are displayed in Table 4.

Table 4: *Reduced CO_2 emissions from PHS generation, extra CO_2 emissions from charge of PHS, net carbon balance for North in 2018. Values in tCO_2.*

	ΔE^S	ΔE^P	ΔE_{PHS}
North	631,044.9	159,273.1	471,771.8

The total amount of saved carbon emissions from generation of PHS power plants for North in 2018 results in 631 $ktCO_2$. This result represents only 5.74% of the total yearly amount of saved CO_2 from hydroelectric power plants in the North, as calculated by Beltrami et al. (2021).
The total CO_2 emitted by thermoelectric power plants to serve the demand of power coming from PHS power plants during charging times was equal to nearly 159 $ktCO_2$. Hence, the net balance of carbon emissions from PHS operations was positive and equal to 471,771.8 tCO_2.
This result is consistent with the argument by Staffell (2017), who specified 73.6% as the coefficient of round-trip efficiency of PHS power plants. Reassuringly, the empirical round-trip efficiency ratio derived for PHS plants for North, based on the results of Table 4, results in 74.8%. This value is perfectly in line with the coefficient found in the literature, thus confirming the value of round-trip efficiency for a typical modern PHS facility.

6 Conclusions

This paper explores the literature on the economic and environmental impact of hydroelectric production and, in particular, of pumped hydroelectric storage (PHS) units within modern electricity grids.

To the best of the author's knowledge, this is the first attempt of investigating the average environmental benefit arising from short-term arbitrage operations related to hydrostorage units of electricity production for aggregate data on the Italian power market. Arbitrage is typical of storage facilities, for which market participants buy electricity at off-peak hours and sell it during higher priced peak hours.

Beyond the research question and the displayed results, the empirical methodology represents an important contribution to the literature. The analysis was feasible only from a thorough codification (type, installed capacity, location) of active hydroelectric power plants in the Italian day-ahead power market. In particular, this paper stresses the distinction between pure PHS units - which can place both demand and supply bids in the market, thus allowing for the adoption of the simulation approach presented in Section 3.2 - and modulable hydroelectric facilities in general, which in turn justify the econometric analysis of marginal effects of hydroelectric generation on levels of carbon emissions. The preliminary technical classification of hydropower units led to adopt this twofold empirical strategy.

The main results of the analysis are the following.

- Data from the Italian day-ahead power market support the expected evidence of a systematic positive difference between peak and off-peak electricity prices at the plant-level, which enables storage facilities to take advantage of the price differences arising between off-peak and peak hours.

- The econometric estimations applied to aggregate data on both PHS and modulable hydroelectric power plants indicate that generation from storage reduces the levels of carbon emissions. In average terms, the empirical storage marginal emission factor (MEF) results in 0.138 tCO_2/MWh. This finding is robust to the variations of electricity generated by intermittent renewable sources and to the changes of load in the grid. By disentangling the effect between off-peak and peak hours, the off-peak MEF from storage amounts to 0.171 tCO_2/MWh, thus revealing potentials for carbon displacement during low demand night-hours. Conversely, the estimated value of the MEF from storage during peak hours is not statistically significant. This shows that generation from storage, individually taken, is not able to modify the structure of marginal generation during peak-demand hours within the considered market zone.

- The computation of the net balance of carbon emissions from PHS charge and discharge operations suggests that the amount of CO_2 saved from the discharge of PHS is larger than the amount of extra CO_2 emitted for the charging process of PHS. This net environmental benefit, which amounts to 471,771.8 tCO_2 not emitted, accounts for losses related to PHS operations and is consistent with the measure of round-trip efficiency generally assumed in the literature, which amounts to nearly 74%.

The author is aware of some limitations in this analysis.

Primarily, the inclusion of a more refined investigation of the nature of the considered time-series variables might add more precision to the obtained MEFs. The unit root and stationarity tests,

together with ACF and PACF plots, can shed some light on the behaviour of the time-series and lastly on the correct model to be used, in order to improve the efficiency of the estimated coefficients from the econometric analysis.
Secondly, the methodology for the simulation exercise relies on a short-term approach by assuming no investments in power plants, that may modify their capacity and accordingly meet the residual load. Moreover, the simulation analysis calculates the social benefit from storage generation without taking into account the costs for the integration of RES into the system. The integration costs of RES into the grid might include balancing, grid-related and adequacy costs (Cretì and Fontini, 2019) which may be included in future simulations for a full evaluation of the penetration of RES in combination with additional investments in storage capacity in the system.
Thirdly, the simulation approach assumes that the merit-order ranking is not affected by strategic bidding of market operators, that may withhold some capacity to affect the outcomes of market equilibria by exploiting some potential for market manipulation.

All in all, it is clear that storage represents an important resource to compensate the high and rather uncontrollable penetration of intermittent RES generation. The investment decision of installing additional hydroelectric storage capacity depends on many technical and geographical factors which need to be accounted when comparing the costs and the benefits connected to pumped hydro storage facilities. However, this issue is outside of the scope of this paper and is left for future research.
Overall, the expansion of hydropower in general, and in particular of *pumped hydroelectric storage* (PHS), can help contributing to the resilience and power quality of the entire grid. The higher penetration of RES, combined with the process of phasing-out carbon-intensive thermal capacity, is creating new opportunities for investors and new challenges for researchers and policy makers for the correct evaluation of the related costs and benefits. The larger diffusion of energy storage facilities in the grid may lead the entire electricity sector within the overall transition towards a low-carbon sustainable economy.

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A Appendix

A.1 Calculating CO_2 emissions at unit level

In order to calculate CO_2 emissions for a typical thermoelectric unit of power generation, the (inverse of) the function of technical efficiency for a fossil fuel power plant is defined. We here assume convex functions to calculate the hourly fuel consumption (expressed in $Gcal/h$), which is a function of the electric power supplied (MWh), given the type of fuel (or fuel mix) used by the power unit.[36]
The fuel consumption function for conventional power plants is given by:

$$g_i^f(Q_{i,h}) = \sum \alpha_i^f (c_{2,i}^f Q_{i,h}^2 + c_{1,i}^f Q_{i,h} + c_{0,i}^f) \tag{7}$$

where the uppercase f stands for the fuel type (natural gas, oil and coal) and $Q_{i,h}$ is the hourly accepted electricity generation. The case of multi-fuel power generators (two at most) is also included.[37] The parameters used to calculate the fuel consumption function by each relevant thermoelectric unit are:

- minimum and maximum power capacity available for every thermal group;
- percentage mix - expressed by the parameter α - of the utilised fuels (set to a maximum number of two fuels available per unit);
- three non-negative coefficients for the hourly consumption quadratic curves (c_2^f, c_1^f, c_0^f), which are specifically related to the fuel used in the mix of production.

Equation (7) allows to transform the quantities accepted for power supply into the required fuel consumption. Then, the hourly consumption of fuel (converted into TJ/h with a standard conversion factor λ) is further transformed into the hourly amount of CO_2 emissions at plant-level using emission intensity factors that depend on the technology type f. Emission factors are derived from average national carbon intensities taken from ISPRA,[38] which depend on the fuel type only. To summarise, unit-level total CO_2 emissions are given by:

$$E_{i,h}^f = \varepsilon^f \cdot \lambda \cdot g_i^f(Q_{i,h}) \tag{8}$$

[36] The quadratic cost functions are frequently assumed in the literature, see for example Cretì and Fontini (2019, p.29). They have been used also by Marcantonini and Valero (2017), who share with this study the methodology for the calculation of hourly fuel consumption of conventional power plants. This model is based on the application of ELFO++, a cost-based deterministic model designed by the energy consulting company REF-4E, which is kindly acknowledged by the author. Furthermore, note that only direct carbon emissions are computed in this study. For a complete characterisation of Life-Cycle Assessment (LCA) emissions produced by units of power generation, please refer to GSE (2015).

[37] Due to lack of data, the extra-efficiency that multifuel plants have by taking advantage of the joint usage of different fuels is not included in this work. Nevertheless, this issue refers only to three power plants. For this reason, the bias in the calculation of emissions can be neglected.

[38] ISPRA (*Istituto Superiore per la Protezione e la Ricerca Ambientale*) is the Italian Institute for the Environmental Protection.

In Equation (8), the sources of variability of hourly CO_2 emissions are: the hourly accepted electricity generation $Q_{i,h}$, the average plant-specific technical efficiency parameter $\lambda \cdot g_i^f$, the average fuel-dependent carbon emission factors (carbon intensity parameters) ε^f.
Specifically, average national fuel-dependent carbon emissions factors (CO_2 intensity) for year 2018 are collected from ISPRA (2018). Table A.1 provides the values used for the analysis, for which it is assumed that the RES technologies are carbon neutral.[39]

Table A.1: *Average national fuel-dependent carbon emission factors in 2018.*

Fuel	$CO_2\,intensity\,(t\,CO_2/TJ)$
Coal	95.124
Natural Gas	57.693
Oil	76.604
RES technologies	0.0

A.2 Data coverage

The total estimated CO_2 emissions from thermoelectric generation in 2018 arising from the outcomes of the Italian MGP market, calculated by means of Equation (8), amounts to 73 Mt CO_2.
As a term of comparison, ISPRA (2020) reports that the total amount of carbon emissions in 2018 from the electricity sector in Italy was 85.4 Mt CO_2,[40] which represented 23.9% of total greenhouse gases emitted by Italy.
Eventually, the entire technical codification process of Italian units of power generation allowed to cover the calculation of carbon emissions for 45.5 GW of thermoelectric installed power capacity, for which market participants placed bids in year 2018 in the MGP.[41] Hence, in this study, nearly 80% of the total active thermoelectric capacity was mapped for the calculation of CO_2 emissions from electricity generation.

[39]GSE (2015) adopts a similar methodology to monitor the carbon footprint of the Italian electricity sector, in compliance with the 2009/28/CE European Directive.

[40]The calculation of total carbon emissions calculated in the present study represents a lower bound with respect to ISPRA official estimation for three main reasons: (1) the lack of data on the efficiency for the whole fleet of installed thermoelectric capacity; (2) the lack of data for self-producers of electricity; (3) the adjustments of production of thermal power plants arising from the outcomes on balancing markets.

[41]Terna (2019) reports that, at the 31st of December 2018, the total installed thermoelectric capacity in Italy was 62.3 GW, of which 56.9 GW related to active operators in the market and 5.4 GW for self-production.

Table A.2: *Descriptive statistics for North in 2018.*

	n	mean	sd	median	trimmed	mad	min	max	range	skew	kurtosis	se
hourly_emissions	8760	4181.05	1469.94	4108.18	4162.90	1684.70	1142.70	8154.95	7012.25	0.11	-0.86	15.71
hourly_generation	8760	14720.87	3760.74	14533.25	14719.01	4515.01	5783.51	26452.47	20668.96	0.04	-0.88	40.18
hourly_generation_intRES	8760	3132.35	1105.13	2798.79	2982.47	845.83	1534.58	6785.13	5250.55	1.09	0.30	11.81
storage_generation	8760	817.14	582.09	733.29	773.33	651.72	18.79	4191.77	4172.97	0.65	0.03	6.22
hourly_load	8760	18780.70	4290.51	18061.58	18745.39	5388.97	10082.23	27717.35	17635.12	0.12	-1.27	45.84
hourly_PHSdemand	8760	7.75	17.72	0.00	3.80	0.00	0.00	303.32	303.32	3.48	20.19	0.19
net_load	8760	18772.94	4295.33	18060.07	18738.94	5389.45	10008.63	27717.35	17708.72	0.12	-1.27	45.89
hourly_price	8760	60.71	15.41	60.40	60.17	14.20	9.39	159.40	150.01	0.61	2.07	0.16
PUN	8760	61.31	14.84	61.21	61.00	14.38	6.97	159.40	152.43	0.39	1.53	0.16

Table A.3: *Descriptive statistics for North in 2018, distinguished by off-peak and peak hours.*

(a) Off-peak hours:

	n	mean	sd	median	trimmed	mad	min	max	range	skew	kurtosis	se
hourly_emissions	4015	3665.95	1244.64	3570.82	3617.21	1346.96	1142.70	7686.95	6544.25	0.33	-0.50	19.64
hourly_generation	4015	12554.69	2999.55	12375.52	12405.41	2965.70	5783.51	22273.97	16490.45	0.43	-0.14	47.34
hourly_generation_intRES	4015	2436.41	412.66	2363.04	2419.23	436.85	1534.58	3556.38	2021.81	0.35	-0.79	6.51
storage_generation	4015	623.57	540.16	514.02	550.66	561.11	18.79	2649.13	2630.33	0.98	0.35	8.52
hourly_load	4015	16228.75	2885.96	15783.07	16066.71	2608.16	10082.23	24240.78	14158.55	0.47	-0.24	45.55
hourly_PHSdemand	4015	10.28	21.02	0.00	5.25	0.00	0.00	146.68	146.68	2.66	8.01	0.33
net_load	4015	16218.47	2892.04	15771.60	16056.98	2617.65	10008.63	24240.78	14232.15	0.46	-0.24	45.64
hourly_price	4015	56.18	13.58	56.69	56.20	14.07	10.00	129.50	119.50	0.10	0.47	0.21
PUN	4015	57.04	13.10	57.56	57.15	13.96	10.00	130.15	120.15	-0.03	0.24	0.21

(b) Peak hours:

	n	mean	sd	median	trimmed	mad	min	max	range	skew	kurtosis	se
hourly_emissions	4745	4616.90	1504.69	4758.44	4668.08	1742.48	1210.37	8154.95	6944.59	-0.23	-0.84	21.84
hourly_generation	4745	16553.79	3341.94	17058.22	16730.27	3458.82	6870.98	26452.47	19581.49	-0.41	-0.47	48.52
hourly_generation_intRES	4745	3721.23	1163.65	3520.89	3653.39	1326.48	1747.16	6785.13	5037.97	0.43	-0.85	16.89
storage_generation	4745	980.93	565.84	931.98	956.15	639.17	36.42	4191.77	4155.34	0.51	0.25	8.21
hourly_load	4745	20940.04	4094.58	22425.40	21263.63	3732.93	10572.87	27717.35	17144.48	-0.62	-0.92	59.44
hourly_PHSdemand	4745	5.62	13.98	0.00	2.59	0.00	0.00	303.32	303.32	4.86	56.63	0.20
net_load	4745	20934.42	4097.83	22422.95	21258.66	3726.50	10465.08	27717.35	17252.27	-0.62	-0.92	59.49
hourly_price	4745	64.55	15.83	63.44	63.63	14.00	9.39	159.40	150.01	0.80	2.44	0.23
PUN	4745	64.92	15.26	64.25	64.35	14.27	6.97	159.40	152.43	0.50	1.86	0.22

Table A.4: *PHS units and their installed capacity distinguished by zone. In bold, the PHS units for which both supply and demand bids were placed in the MGP in 2018. Source: own elaboration by matching GME data.*

Unit name	Market zone	Installed capacity
Entracque	North	1064 MW
Roncovalgrande	North	1000 MW
Edolo	**North**	**950 MW**
Santa Massenza 1 (Molveno)	**North**	**377 MW**
Venina	North	327 MW
Bargi	North	281 MW
San Fiorano	North	271 MW
Fadalto	North	220 MW
Gargnano	North	137 MW
Entracque Rovina	North	125 MW
Riva del Garda - Nuovo	**North**	**117 MW**
Lanzada	North	117 MW
Pracomune	**North**	**35 MW**
Telessio	**North**	**35 MW**
Presenzano	Center South	1005 MW
San Giacomo	**Center South**	**490 MW**
Provvidenza	**Center South**	**139 MW**
Capriati	Center South	113 MW
Anapo	Priolo	500 MW
Guadalami	Sicily	80 MW
Taloro	Sardinia	240 MW

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