The Value of Electricity Storage Arbitrage on Day-Ahead Markets across Europe

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Abstract

This paper investigates the historical value of electricity storage from the perspective of the storage owner in day-ahead market (DAM) across Europe. A technology-neutral formulation is used, where the storage is modelled based on its round-trip efficiency and storage duration. A mixed-integer linear program (MILP) is built to compute the perfect-foresight value of a price-taker storage from arbitrage, using historical hourly DAM prices in all the bidding zones of the EU-28 countries, Norway, Switzerland, and Turkey. Depending on the bidding zones, the DAM price data starts between 2000 and 2017, and spans to 2021. The model is solved for varying round-trip efficiencies (50% to 100%) and storage durations (1 to 10 hours) for every bidding zone and every year in the dataset. The results reveal significant variations in storage value from arbitrage, both geographically and temporally, with round-trip efficiency having a major impact on arbitrage value and storage duration having very low marginal value beyond 4 to 6 hours. Additionally, the paper investigates the impact of variable grid fees on arbitrage value, using the case of Belgium, where fees depend on storage system size. The initial MILP is therefore augmented to account for the complex dependencies between storage size and the resulting grid fees. The augmented MILP shows that grid fees can decrease storage arbitrage value by 20% to 50%, and that they can also dramatically decrease storage participation in DAMs.

Keywords: Energy storage, Arbitrage, Day-Ahead market, Mixed-Integer Linear Programming, Grid Fees.

1. Introduction

Large-scale electricity storage systems have become increasingly common in modern power systems, with the EU-28 countries, Norway, and Switzerland currently accounting for a combined total of 49 GW and 1313 GWh of pumped hydro energy storage (PHES), 321 MW of compressed air energy storage (CAES), and just under 20 MW of battery energy storage systems (BESS), as reported by Geth et al. (2015). As the energy sector undergoes a transition and the share of renewables continues to grow, the demand for electricity storage is expected to rise even further.

Regarding the economics of energy storage, a fairly extensive and diverse literature already exists, as summarized in Table 1. The diversity lies in several aspects, starting from the storage technology itself. While the main studied technologies are PHES, CAES and BESS, some authors adopt a technology neutral approach, with valuation models relying only on the storage high-level parameters.

In addition, there is variation in how researchers approach the key storage parameters of round-trip efficiency and storage energy capacity. While some studies use fixed values for these parameters, others perform sensitivity analyses by allowing them to vary. Furthermore, some studies treat storage energy capacity as a decision variable to optimize storage value given a capital expenditure (CAPEX) function.

The diversity of research in this area is also reflected in the range of valuation models employed, which include heuristics, linear programming (LP), mixed-integer linear programming (MILP), mixed-integer non-linear programming (MINLP), mixed-integer quadratically constrained programming (MIQCP), dynamic programming (DP), or chance-constrained programming (CCP) frameworks.

The valuation model is designed to suit the revenue streams that are being considered, which may come from one or a combination of energy-only and

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Reference	Storage technology	Round-trip efficiency	Storage duration	Modelling technique	Valorized markets	Market locations	Data range	Grid fees	CAPEX	Notes
Sioshansi et al. (2009)	Neutral	50-90%	0.5-30 h	LP	RT	US (PJM)	2002-2007	No	No	High sensitivity to year, round-trip efficiency, storage duration up to 10 h.
McConnell et al. (2015)	Neutral	75%	0.5-10 h	LP	RT	AU (NEM)	2004-2014	No	No	High sensitivity to year and storage duration up to 4 h. Negligible sensitivity to round-trip efficiency.
Lin et al. (2019)	LAES	60%	Variable	Heuristic	RT	GB	2015	No	Yes	Liquid air energy storage optimal sizing.
Bassett et al. (2018)	Neutral	80%	1 h	Heuristic	RT	CA (ON)	2015	No	No	Hourly Ontario Energy Price (HOEP).
Adebayo et al. (2018)	Neutral	80%	5 h	MILP	RT	CA (AB)	2010-2014	Yes	No	Price taker, impact of grid fees.
		75%	12 h	MILP	RT	CA (AB)	2010-2014	Yes	No	Price maker, impact of grid fees.
Bradbury et al. (2014)	Multiple	0-100%	0-30 h	LP	RT	US (NY-ISO, ERCOT, PJM, SPP, MISO, CAISO, ISONE)	2008	No	Yes	PHES and CAES most valuable technologies. Optimal energy capacity function of storage technology.
Barbry et al. (2019)	Neutral	81%	3 h	MIQCP	DAM	US (NY-ISO)	2016	No	No	Robust price-maker optimization.
Spisto (2014)	PHES	85%	2 h	LP	DAM	IT	2005-2013	No	Yes	Most value in Sicily. Negative NPV.
Wilson et al. (2018)	PHES	75%	8 h	Heuristic	DAM	DE, UK	2010-2016	No	No	Revenue distribution within each year.
Arcos-Vargas et al. (2020)	BESS	92-94%	1-10 h	MILP	DAM	ES	2016-2017	No	Yes	Negative NPV. Simulate CAPEX decrease and battery life extension.
Zafirakis et al. (2016)	PHES	77%	Variable	Heuristic	DAM	Nordpool, EEX, GB, ES, GR	2007-2011	No	Yes	Significant deviations between countries and years.
	CAES	106%	Variable	Heuristic	DAM		2007-2011	No	Yes	
Connolly et al. (2011)	PHES	85%	6/24 h	Heuristic	DAM/RT	Nordpool, AT, IE, IT, ES, PT, GB, AU, NZ (NI), CA (AB, ON), US (NY, NE)	2008	No	Yes	High value variation between regions.
	PHES	85%	6 h	Heuristic	DAM/RT	Nordpool, GB, PT, IT, CA (AB), US (NE)	2005-2009	No	Yes	High value variation from year to year.
CREG (2015)	PHES	65%/75%	6 h	Not specified	DAM	BE	2014	Yes	Yes	Fixed and variable grid costs. Not clear whether variable grid costs impacting Dispatch decision or applied ex-post.
	BESS	90%	6 h	Not specified	DAM	BE	2014	Yes	Yes	Distinction between TSO/DSO levels.
	PHES	65%/75%	6 h	Heuristic	aFRR	BE	2014	Yes	Yes	Operation range is not taken into account.
	BESS	90%	6 h	Heuristic	aFRR	BE	2014	Yes	Yes	

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Table 1: Literature on the market value of energy storage in power systems.

Continued from previous page

Reference	Storage technology	Round-trip efficiency	Storage duration	Modelling technique	Valorized markets	Market locations	Data range	Grid fees	CAPEX	Notes
Brijs et al. (2019)	Neutral	75%	4 h	MILP	DAM, CIM, RT	BE, FR, NL, DE	2014	No	No	Cross-market optimization, with price effect for the BE case.
Kazempour et al. (2009)	BESS	90%	7 h	MINLP	DAM, reserves	ES	1 week	No	Yes	IRR = 17%
	PHES	67%	7 h	MINLP	DAM, reserves	ES	1 week	No	Yes	IRR = 29%
Yu and Foggo (2017)	BESS	80-94%	1-8 h	Stochastic LP	DAM, reserves	US (CAISO)	2013-2014	No	No	Reserves market most profitable. High sensitivity to round-trip efficiency and energy capacity.
Chazarra et al. (2014)	PHES	Constant	220	MILP	DAM, reserves	ES	2012-2013	No	No	Efficiency is power dependant.
Staffell and Rustomji (2016)	BESS	40-100%	1-10 h	Heuristic	DAM, reserves	GB	2013-2014	No	Yes	Reserves provision could triple profits.
Toubeau et al. (2020)	Neutral	64%	4.8 h	CCP	DAM, reserves	BE	2015-2018	No	No	Chance-constrained programming.
		90%	1.2 h							
Pinto et al. (2011)	PHES	70%	N/A	LP	DAM, reserves	PT	10/04/2010	No	No	No operation range constraints.
Drury et al. (2011)	CAES	60-90%	2-40 h	MILP	DAM, reserves	US (CAISO)	2009-2010	No	Yes	Conventional CAES vs adiabatic CAES.
						US (MISO)	2009	No	Yes	
						US (NY-ISO)	2002-2009	No	Yes	
						US (PJM)	2005-2009	No	Yes	
Berrada et al. (2016)	Gravity	85%	4 h	LP	DAM, RT, reserves	US (CAISO)	01/12/2015	No	No	Compared with PHES & CAES.
Moreno et al. (2015)	Neutral	85%	1.66 h	MILP	Multi-service	GB	2011-2013	No	No	Full operation range.
Oudalov et al. (2006)	BESS	N/A	N/A	Heuristic	Multi-service	N/A	N/A	No	Yes	Order of magnitude analysis. Independently valorized applications: load levelling, FCR, end-user peak shaving.
Oudalov et al. (2007)	BESS	70%	Variable	Heuristic	FCR	DE	2005	No	Yes	2005 frequency data, 2001-2007 DE FCR prices.
Mercier et al. (2009)	BESS	70%	Variable	Heuristic	FCR	Fictive	Fictive	No	Yes	Fictive small isolated power system.
Jomaux et al. (2015)	BESS	81%	Variable	Heuristic	FCR	BE	2014	No	Yes	Optimal sizing of the energy ratio.

Table 1: Literature on the market value of energy storage in power systems (continued).

reserves markets. In Anglo-Saxon countries, valuations are generally based on either a real-time (RT) market or a day-ahead market (DAM) coupled with reserves provision. In Europe, the energy-only markets that are usually considered are DAMs, but they may also include continuous intraday markets (CIM) or imbalance markets, while the reserve products that are taken into account may be frequency containment reserves (FCR), frequency replacement reserves (FRR), or restoration reserves (RR). Some studies also look into the provision of services to distribution grid operators (DSO). When valuing on energy-only markets, the storage model can remain neutral, meaning that it does not need to be tailored to a specific technology, since the optimal dispatch will always push the unit to the rated power. However, when providing reserves, the storage model needs to consider the operating range of the technology being studied. Pumped hydro energy storage (PHES), for example, typically has restricted operation ranges that prevent it from operating across the full range from 0 MW to the rated power Mercier et al. (2017a,b); Iliev et al. (2019); Toubeau et al. (2019b,a). Some authors fail to account for this, which can lead to over-optimistic valuation results.

The market locations under study vary from one paper to another, with most works focusing on a single bidding zone or just a few ones. Sometimes, valuation is based on the hourly series of a DAM index such as Nordpool or EEX, which are weighted average prices or prices under the assumption of unlimited cross-border capacity between the composing market locations. In such cases, valuation disparities between composing locations are concealed by the index.

Finally, the valuation horizon also varies significantly between papers, ranging from one day to one or a few years at most. To the best of our knowledge, no study has examined the long-term evolution of storage value over a horizon of up to 20 years, even on a single market such as the DAM, let alone a wide range of countries or bidding zones.

Looking more specifically at some of the papers listed in Table 1, reference Sioshansi et al. (2009) investigates the arbitrage value of a perfectly forecasting price-taker storage in the PJM market, in function of both the round-trip efficiency and the number of storage hours. The paper shows that 8 hours of storage enable to capture about 85% of the potential arbitrage value, while 20 hours of storage enable to capture 95% of the arbitrage potential. Besides, the paper shows a strong influence of the round-trip efficiency on arbitrage revenues. The influence of other parameters is also investigated, among which the price taker hypothesis, fuel prices, and the impact of imperfect forecasting.

In McConnell et al. (2015), the revenues of energy storage are assessed on Australia's energy-only wholesale market, the National Electricity Market. The storage is modelled as a perfectly forecasting price-taker and the revenues are found to be relatively insensitive to the round-trip efficiency, as they are mostly made on price spikes occurring a few days a year.

The impact of grid tariffs on the value of energy storage is for the first time studied in Adebayo et al. (2018), in the specific case of the energy-only market in Alberta, on the period 2010-2014. Depending on the year, grid fees are found to decrease the annual value between 15% and 40%.

Reference Bradbury et al. (2014) computes the arbitrage value of 14 different energy storage technologies in 7 RT markets in the United-States, based on 2008 historical prices. The authors find that the optimal energy capacity is function of the cost structure of each storage technology.

In Spisto (2014), the author investigates the profitability of PHES on the Italian DAM given historical hourly prices from 2005 to 2013.

Reference Arcos-Vargas et al. (2020) computes the NPV of a battery with varying energy capacity in the Spanish DAM.

In Zafirakis et al. (2016), the authors derive the arbitrage value of PHES and CAES based on the 2007-2011 DAM prices in the UK, Spain, Greece, and on the power indices of Nord Pool and EEX. Significant value variations are observed between the studied regions, as well as along the years.

Reference Connolly et al. (2011) investigates the perfect foresight revenues of a PHES unit in 13 electricity spot markets in Europe, USA, Canada, Australia and New Zealand. The authors show that revenues vary dramatically from one market to another, and that operating the storage on successive 24-hour horizons enables to capture 97% of the revenues that would be achieved if the optimization horizon was a full year.

In Brijs et al. (2019), the authors derive the 2014 arbitrage value of storage on the DAM, CIM and RT market in Belgium, France, the Netherlands, and Germany. For each country, the authors investigate the value when operating the storage (i) individually on each of the three markets, (ii) sequentially on the three markets, (iii) in a coordinated fashion on the three markets. In the most realistic scenario of sequential cross-market valuation, the value extracted from the RT market reaches the value achieved on the DAM, thereby doubling the total revenues. In this sequential approach, the CIM value is negligible.

In Kazempour et al. (2009), the authors study the revenues of a price-taker battery storage taking part in the Spanish DAM, as well as in the spinning reserve and regulation markets. Over the one-week studied horizon, results show that the battery actively participates in the spinning reserves market, as compared with the DAM and regulation markets, because of the higher potential profit in the former.

In Yu and Foggo (2017), the authors perform a stochastic valuation of a BESS based on forecasted series of CAISO SP15 electricity and frequency regulation prices. The authors show that most of the revenues come from frequency regulation services, and that both the round-trip efficiency and the storage energy capacity are crucial parameters of the valuation.

In Chazarra et al. (2014), the revenues of PHES in the Spanish system are studied with and without the ability to regulate power in pump mode. The PHES unit is modelled as a price taker, perfectly forecasting prices, and taking part in both the DAM and the secondary regulation reserve markets. Outcomes reveal that the secondary regulation reserve market proves to be the main source of revenue for the PHES unit.

In Staffell and Rustomji (2016), the authors develop an algorithm to maximise the profit of both sodium sulphur (NaS) and lithium ion (Li) BESS performing arbitrage and providing reserves on the UK market. Although the internal rates of return (IRR) computed based on historical 2013-2014 power and reserves data are positive, they are too low to justify investment in these storage technologies.

Reference Pinto et al. (2011) investigates the revenues of a perfectly forecasting price-taker PHES unit, simultaneously taking part in the Iberian DAM as well as in the Portuguese ancillary services market. The paper shows that the revenues made by the PHES unit almost entirely come from the spinning reserve market, and the higher the wind penetration, the higher the revenues. Interestingly, the PHES unit behaves as an energy buyer on the DAM, i.e. it generates a negative revenue on this market.

In Drury et al. (2011) the authors study the value of CAES, both conventional and adiabatic, providing operating reserves in addition to energy arbitrage in several US markets. They find that the provision of reserves increases CAES net revenues to the point of making conventional CAES profitable in several of the studied markets. Adiabatic CAES remains unprofitable though.

In Berrada et al. (2016), the authors value PHES, CAES and a gravity storage on the DA and RT NYISO energy and regulation markets.

In Moreno et al. (2015), the authors value a distributed energy storage providing multi-services in Great Britain (GB), including energy price arbitrage, balancing services and DSO congestion reduction through active and reactive power control.

As indicated in Table 1, several papers investigate the economics of BESS proving FCR. While reference Jomaux et al. (2015) arbitrarily focuses on the provision of FCR, the incentive for Oudalov et al. (2007); Mercier et al. (2009) is that Oudalov et al. (2006) identifies the provision of FCR as the application with the highest value for battery owners, alternative applications being load levelling for postponement of transmission and distribution upgrades, and load peak shaving at industrial end-customer.

This paper contributes to the existing literature on energy storage economics by examining the long-term evolution and geographical disparities of arbitrage value on the day-ahead markets (DAMs) across Europe, from the perspective of individual storage owners. Sensitivity analyses are conducted to assess the impact of round-trip efficiency and storage duration, while the effect of grid fees is for the first time formally modelled and assessed over multiple years, specifically in the liberalized Belgian market. The study stands out for its extensive and diverse temporal and geographical scope, with every single bidding zone in the EU-28 countries, as well as Norway, Switzerland and Turkey, being examined. Historical data from 2000 to 2021 is used, and for the first time, DAM valuations of electricity storage are performed in Switzerland (CH), Estonia (EE), Latvia (LV), Lithuania (LT), Poland (PL), Czechia (CZ), Slovakia (SK), Hungary (HU), Slovenia (SI), Croatia (HR), Serbia (RS), Romania (RO), Bulgaria (BG), and Turkey (TR). Additionally, the paper makes a distinction between the countries of the Nordic region, Denmark (DK), Norway (NO), Sweden (SE), and Finland (SI), instead of valuing based on the

Nordpool system price. Overall, this paper provides a comprehensive analysis of the arbitrage value of energy storage on the DAMs across Europe, offering valuable insights on geographical and temporal disparities between and within the different regions. The inclusion of sensitivity analyses and the assessment of grid fees further enhances the paper's contribution to the field of energy storage economics.

The paper is organized as follows: the history and evolution of European day-ahead markets is discussed in Section 2; the valuation models, their implementation and the input data are presented in Section 3; valuation results are presented in Section 4 and put in perspective in Section 5; while conclusions are made in Section 6.

2. Evolution of European Day-Ahead markets

Day-ahead markets (DAM) are energy-only markets wherein electricity is traded through the daily auction of 24 hourly contracts. To participate in the DAM, market participants must submit their bids before the gate closure, which is typically at 12:00 CET on day D-1 for all 24 hourly contracts. After the gate closure, the auction results are published within an hour, allowing market participants to quickly prepare for the delivery/offtake on the next day.

The origin of European DAMs lies in the liberalization of the European energy sector, that took off in the late '90s and created the need for market participants to trade electricity on organized wholesale markets Boisseleau (2004). National power exchanges started popping up everywhere in Europe, enabling market participants to trade electricity on their local DAM, one day before delivery. Several regional initiatives were subsequently launched to couple the different local DAMs European Network of Transmission System Operators (ENTSO-E) (2021); Nemo Committee (2021) and make the best of existing inter-connectors; the ultimate goal being to increase the total welfare. The development and progressive coupling of European DAMs occurred simultaneously and in accordance with an evolving European legislative body, including Directives 96/92/EC, 2003/54/EC, 2009/72/EC and (EU) 2019/944, as well as Regulations (EC) 1228/2003, (EC) 714/2009, (EU) 2019/943, in addition to Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (CACM), and targeting a pan-European single day-ahead coupling (SDAC).

In the Nordic region, the movement toward a single electricity market started in 1999 with the launch by Nord Pool of a DAM enabling to trade in Norway, Sweden and Finland, quickly followed by Denmark who joined the power exchange in 2000. Nord Pool then opened bidding areas in Lithuania and Latvia, respectively in 2012 and 2013 Nord Pool (2021).

In Central-West Europe (CWE), the movement started in November 2006 with France, Belgium and the Netherlands integrating their own market floors into the tri-lateral market coupling (TLC), which in November 2010 further evolved into the CWE Market Coupling with the integration of Germany European Power Exchange (EPEX SPOT) (2021).

In South-Western Europe (SWE), Spain and Portugal integrated their DAMs in July 2007, creating the Iberian Electricity Market (MIBEL) operated by the exchange OMIE Iberian Eectricity Market (MIBEL) (2021).

In Central-Eastern Europe, Czech Republic and Slovakia coupled their DAM in 2009, before morphing into the 3M Market Coupling (3MMC) with the inclusion of Hungary in 2012, to further evolve into 4MMC with the inclusion of Romania in November 2014 Hungarian Power Exchange (HUPX) (2021).

After an initial expansion phase, started a second phase where the different coupled regions began coupling to each other. In February 2014, price coupling went live in North-Western Europe (NWE), including Belgium, Denmark, Estonia, Finland, France, Germany/Austria, Great Britain, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland (via the SwePol Link), and Sweden. It was the first initiative to use the pan-European Price Coupling of Regions (PCR) solution for the simultaneous calculation of market prices and flows on interconnectors with one single shared algorithm called Euphemia. The same solution was also used at the same time in the SWE region in a common synchronised mode, and the full coupling of NWE and SWE started in May 2014, giving birth to the so-called Multi Regional Coupling (MRC). Since then, the scope of the MRC increased with the inclusion of Italy and Slovenia in February 2015, Croatia in June 2018, Ireland in October 2018, Greece in December 2020 and Bulgaria in May 2021. In June 2021, 4MMC and MRC coupled with one another, while the border between Romania and Bulgaria was included in SDAC in October 2021. To be also noted, the split in October 2018 of the German-Austrian bidding zone into two separate ones, and the exit in January 2021 of the EU-GB interconnectors and the GB bidding zone from the MRC coupling.

Another major event occurred in May 2015 when the CWE countries switched to the flow-based market coupling (FBMC), which is a more efficient calculation process of their internal cross-border capacities. Briefly, the FBMC allocates transmission capacities at the same time as the market clearing. This replaces the usual available transfer capacity (ATC) where the capacity allocation takes place prior to market clearing. The FBMC ensures greater cross-border transport capacity through the closer integration of capacity allocation and market activity.

Further developments are expected with, in the first half of 2022, the implementation of flow-based implicit allocation for the Core Capacity Calculation Region in the framework of the Core Flow-Based Market Coupling Project. Together with the CORE flow-based project, the Croatian-Hungarian border will be included in the SDAC coupling.

The convergence induced by the progressive integration of European DAMs is key in understanding the evolution of DAM prices and their dynamics, as well as the impact on energy storage arbitrage value. However, this convergence is only one of the several drivers of DAM prices over the last decade, among which the declining electricity demand, culminating with the COVID pandemic, but also the constantly increasing penetration of low marginal-cost renewable generation, in addition to the low CO2 and gas prices that remained until the gas crisis beginning in 2020. On average, European DAM prices experienced a continuous decrease from 2011 to 2016, before rallying with increases in 2017 and 2018 on a background of economic growth and increasing fuel prices, followed by 2019 and 2020 COVID-related decreases, to then surge in 2021 to unprecedented levels. For more information on on the evolution of the convergence of European DAMs, and on the evolution of market prices, the reader is referred to Zachmann (2008); Böckers and Heimeshoff (2014) and on ACER[1] annual reports on the results of monitoring the internal electricity and natural gas markets The Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets (2022).

[1] ACER, the European Union Agency for the Cooperation of Energy Regulators.

3. Modelling framework

The analysis aims at evaluating the maximum theoretical value of energy storage arbitrage over the past years on European DAMs. Revenues from capacity markets, other energy-only markets, reserves and ancillary services are therefore disregarded.

Although the objective is to maximize the value of energy storage over yearly horizons, the daily nature of DAM auctions implies daily optimizations of storage bidding. By the gate closure of each daily auction, at 12:00 CET, the storage charge-discharge path $(c_h,\, d_h)$ is optimized over a time horizon starting on the first hour of the next day, and spanning $T > 24$ hours. The charge-discharge path is chosen to maximize the arbitrage profit function[2]:

$$\max_{d_h, c_h} \left[\underbrace{\sum_{h=1}^{24} \hat{P}_h (d_h - c_h)}_{\text{Translates in bids}} + \underbrace{\sum_{h=25}^{T} \hat{P}_h (d_h - c_h)}_{\text{Re-optimized next day}} \right]$$

subject to some constraints on c_h and d_h, and on the energy level, including maximum, minimum, initial and terminal energy levels, and conditional on the expectation of future prices that are based on the then available information set Ω_{GC}, which includes all historic data available at gate closure time:

$$\hat{P}_h \equiv \mathbb{E}\left[P_h \mid \Omega_{GC}\right] \quad \forall h$$

While the optimal charge-discharge path on the first 24 hours translates into bids submitted to the day-ahead auction, the subsequent hours are not committed, and are instead re-optimized on the next day, based on the information set available at gate closure on that next day.

Our goal is not to reproduce the operation of energy storage, but rather to value arbitrage on the DAM in way that is reasonably in line with the practicalities of that market. The above optimization problem is therefore simplified by taking the classical perfect-foresight and price-taker assumptions. The perfect-foresight hypothesis allows to consider the hourly DAM prices as known in advance and with full certainty. This deviates from reality since, in practice, storage operators carry out non-optimal DAM biddings based on price forecasts that differ

[2] Ignoring discounting, costs, storage decay, etc.

from the actual clearing prices. Although leading to overoptimistic results, the perfect-foresight hypothesis is, and remains, a quite valuable framework. Relying on it provides us with an upper-bound benchmark of storage value from arbitrage, which can be used to compare countries and years, and against which real-life storage operators can compare themselves. If not done yet, storage operators can easily monitor their performance against this benchmark, and get a good idea of the value percentage they are used to capture, given their forecast methodology and bidding strategy. Another advantage of the perfect-foresight hypothesis is that it does not require the generation of forecasts or the simulation of practical bidding strategies, to which the results remain limited to. Instead, the perfect-foresight assumption dismisses the never-ending questions on the arbitrage value that would have been achieved with better forecasts or more sophisticated bidding strategies.

The reliability of the perfect-foresight approach was tested by Sioshansi et al. (2009) in the specific case of a 12-hour duration storage in the PJM market, in the US. Over the period 2002-2007, the authors optimized an energy storage in any given two-week period using hourly price data for the two previous weeks, and found that the arbitrage value with this simple two-week backcasting approach enabled to capture 85% to 90% of the perfect-foresight arbitrage value. The authors considered this no-foresight backcasting approach as a lower bound of arbitrage value, that could almost certainly be enhanced by basic forecasting of e.g. nearer-term changes in weather and other short-term load and supply effects. Therefore, they judged the perfect-foresight approach as providing a reasonable estimate of storage value from arbitrage.

A contrasted view is given in Antweiler (2021). Using his own forecasting model, the author shows that the impact of forecasting vs perfect-foresight reduces arbitrage value in the RT market of Ontario, Canada, by about half and sometimes (much) more depending on the node. This result, which obviously translates the difficulty of the author to forecast RT prices in Ontario, may be understandable given the high volatility observed in this market. Over the 3-year period under study, 2014-2017, the Hourly Ontario Energy Price (HOEP) turned negative 5500+ hours, i.e. more than 20% of the time, while the standard deviation of prices was about 150% of the average price.

It seems important to stress here that RT markets are completely different markets than European day-ahead markets. While RT prices are the outcome of events/information not fully available 24 hours before delivery, which at least partly explains the difficulties faced by Antweiler (2021) to predict those prices 24 hours in advance, European day-ahead prices are the result of a clearing made the day before delivery, based on information available just before the clearing. Forecasting one day before delivery should therefore be much easier when it comes to day-ahead prices compared to RT prices. Besides an easier forecasting of prices, complex bidding products at European day-ahead exchanges, e.g. exclusive[3] and loop[4] blocks, facilitate the finding by storage operators of (the most) suitable charge/discharge hours in order to maximize profitably. This is obviously not possible in RT markets. The real-life value of arbitrage in day-ahead markets is actually not only function of the accuracy of price forecasts, but also of how these forecasts are translated into the complex bidding products offered by power exchanges. Assessing the impact of forecasting and bidding on arbitrage value, in all the bidding zones studied in this paper, is however out of our scope. Instead, we rely on the perfect-foresight framework and use it as common ground for the comparison of valuation results between bidding zones and years. Besides, while we acknowledge the inherent limitations of perfect-foresight modelling, our reliance on day-ahead prices, instead of intraday or imbalance prices, reduces the potential impact of hindsight bias. We leave the empirical analysis of the value of forecasting to future studies.

The price-taker assumption enables to consider DAM prices as given, i.e. not influenced by the storage actions, which elegantly simplifies the modelling as it neglects the interplay of supply and demand and its impact on prices. Modelling the price effects would require data on, or modelling assumptions regarding the supply and demand curves. While it is virtually impossible to get data on the hourly supply and demand curves for our whole set of countries and years, each market has its own and specific supply and demand dynamics that can not realistically be mod-

[3]Loop blocks: families of two blocks which are executed or rejected together. They allow to bundle buy and sell blocks to reflect storage activities. EPEX SPOT (2023).

[4]Exclusive blocks: group of blocks within which a maximum of one block can be executed, so that electricity is traded at the most profitable moment. EPEX SPOT (2023).

elled, whether with a one-by-one or a one-size-fits-all approach. As we rely on the price-taker assumption, our valuation results are valid for (i) already existing storages, no matter their power rating, since they were exposed to the historical DAM prices, and (ii) a marginal storage with a sufficiently low power rating so that it would have been able to capture historical DAM prices without moving them. The analysis in this paper is historical and does not aim at valuing energy storage expansion, which justifies the price-taker assumption.

As a side note, the price-taker assumption is in line with the Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT), that prohibits, among others, market manipulation. In its guidance on that regulation, ACER identifies capacity withholding as a type of market manipulation The European Union Agency for the Cooperation of Energy Regulators (ACER) (2021) that "occurs, for example, when a market participant with the relative ability to influence the price or the interplay of supply and demand of a wholesale energy product, decides, without justification, not to offer or to economically withhold the available production, storage or transportation capacity on the market." It is therefore understood that storages should bid on the DAM as price takers, since any bidding based on a price-maker hypothesis would be a REMIT breach assimilated to capacity withholding.

3.1. Simple MILP formulation

The energy storage is modelled as price taker, with perfect foresight of the hourly DAM prices, P_h. Besides, the model is developed with the idea of being valid for as many energy storage technologies as possible. Therefore, the technical constraints of our standard energy storage are limited to a round-trip efficiency, η, a storage duration, S_{max}, and the impossibility to charge and discharge the storage at the same time. The storage duration, or energy to power ratio, refers to the discharge time in hours [h], assuming that the energy storage device is discharged at rated power. Modelling the energy storage through its duration instead of through the combination of a rated power and an energy capacity is a convenient way of decreasing the dimensionality of the valuation exercise, which is only possible thanks to the price-taker assumption[5].

[5]As explained in Section 3.2, taking grid fees into account will require to consider the storage rated power as well.

Sets
H the set of hours h in the optimization horizon

Parameters
$P_h \ \forall \ h$, the day-ahead market prices in €/MWh
η, the storage round-trip efficiency
S_{max}, the storage duration

Variables
$c_h, d_h \ \forall \ h$, the charging and discharging rates at hour h
$b_h \ \forall \ h$, binary variables for choosing the operation mode
$s_h \ \forall \ h$, the storage energy level at hour h

Objective function

$$\max \sum_h P_h (d_h - c_h) \tag{1}$$

Constraints

$$0 \leq d_h \leq b_h \quad \forall \ h \tag{2}$$
$$0 \leq c_h \leq (1 - b_h) \quad \forall \ h \tag{3}$$
$$0 \leq s_h \leq S_{max} \quad \forall \ h \tag{4}$$
$$s_{h+1} = s_h - d_h/\sqrt{\eta} + c_h\sqrt{\eta} \quad \forall \ h \tag{5}$$
$$s_0 = S_{max}/2 = s_{\mathrm{card}(H)} \tag{6}$$

Figure 1: Simple MILP maximizing the arbitrage value of a price-taker energy storage with perfect foresight of prices and no grid fees.

In a first instance, grid fees are not taken into account. Although in practice they influence the optimal dispatch of energy storages, grid fees vary geographically and taking them into account would bias the DAM arbitrage value, misrepresenting both the value evolution over time and the comparison between countries. Besides, given the large number of countries studied in this paper, identifying and modelling complex country-specific grid fees is a tremendous work that is out of the scope of this paper. Further in the paper, the impact of grid fees is studied in the specific case of Belgium.

The model is cast as a MILP, whose formulation is given in Figure 1. The objective function (1) represents the revenue maximization considering a price-taker approach and perfect foresight of the hourly DAM prices. Eq. (2) and (3), with the binary variables b_h, prevent charging and discharging at the same time. The constraints on the storage energy level are represented by (4) and (5), while the storage levels at the start and the end of the optimization horizons are set by (6).

Instead of running the model on yearly horizons, which would be unrealistic given our reliance on the perfect-foresight hypothesis, a rolling approach is chosen whereby for each day D of the year, the arbitrage value is computed by running the simple MILP of Figure 1 on a horizon of 7 days, from D to D+6. The yearly arbitrage value is then computed as the sum of the daily arbitrage values. For each 7-day run, the initial energy level is set equal to the end-of-first-day energy level computed in the previous 7-day run. While this daily rolling approach on 7-day horizons enables variable start- and end-of-day energy levels, it also justifies the use of the perfect-foresight hypothesis. Indeed, while we are dealing with horizons of 7 days only, the impact of forecast uncertainty on the first-day optimal dispatch decreases along the 7-day horizon, with only the first days being critical.

3.2. Augmented MILP formulation

Grid fees are generally composed of several components, some of them being related to the power plant's rated power (€/MW), its energy offtakes and injections (€/MWh), or its reactive power offtakes and injections (€/MVAr). In this paper, we investigate the impact of grid fees on arbitrage value, limiting ourselves to the energy components of the grid tariff. This choice is justified since the power component is only relevant for investment decision and is not impacting the actual dispatch of the storage. Besides, although there might be a link between the reactive power offtakes/injections and their active counterpart, this link is assumed negligible.

As above-mentioned, grid tariffs are country specific and their structure can be complex. Therefore, their impact is only investigated in the specific case of Belgium. Grid tariffs on the Elia grid are retrieved from the regulator CREG (2021) and summarized in Tables 2 and 3. Fees F1 to F7 are additive and apply to the offtake of every power plant on the Elia grid, regardless of their specific location in Belgium. Depending on the region where the power plant is located, which can be Flanders, Wallonia or Brussels, additional offtake fees must be added, respectively F8 to F10, F11 to F13, or F14. Fee F15 is the only one applicable to power injections. As emphasized in Table 3, rates F5 and F7 are degressive with the yearly offtake, and their resulting EUR amounts are capped. The rate degressivity and the cap were designed to limit the impact of the related fees on big offtakers. Since they also apply to the offtake of energy storage, they introduce a storage-size dimension in the impact of grid fees on arbitrage value, which must be correctly accounted for by the valuation model.

To account for grid fees in the computation of storage value from arbitrage, the MILP of Figure 1 is augmented to become the one of Figure 2. Three additional variables are defined to account for grid fees: f_{base} summing up the non-capped offtake and injection fees, and f_{cap1} and f_{cap2} respectively for the two capped fees F5 and F7. These 3 additional variables decrease the arbitrage value and are therefore subtracted from the objective function (7). The MILP is also complemented with additional constraints, (8) to (29). Equations (8) to (10) set absolute bounds on f_{base}, f_{cap1} and f_{cap2}, which must all be positive while the two latter are capped. Equation (11) computes f_{base} as the sum of the non-capped components of offtake and injection fees, with R_c the sum of applicable rates among F1 and F14, outside F5 and F7, multiplied by the total charge hours, and R_d = F15, multiplied by the total discharge hours. Equations (12) to (16) are five either-or constraints, each associated with one degressivity rate of Table 3, and a corresponding binary variable x_i. Equation (17) ensures that one and only one of the five either-or constraints is binding, thereby applying the appropriate degressivity rate. The constant $M = 10^7$ is chosen high enough to ensure that the either-or constraints are not binding if their associated binary variable x_i equals 1. The computation of f_{cap1} based on the appropriate degressivity rate, applied on R_{cap1} = F5, and the cap are achieved through (18) to (22) and (28), with y_2 selecting whether one of (18) to (22) is binding, or whether (28) is binding. The computation of f_{cap2} is based on the same logic but with Equations (23) to (27) and (29), and with R_{cap2} = F7. The constant $N = 10^8$ is chosen high enough to set the either-or constraints binding/non-binding in function of the value taken by the binary variables y_i.

It is worth noting here that setting R_d, R_c, R_{cap1} and R_{cap2} at 0 €/MWh results in f_{base}, R_{cap1} and R_{cap2} being null, which makes the augmented MILP of Figure 2 equivalent to the simple MILP of Figure 1.

Because of the dependence of the fees F5 and F7 on the yearly charging volume, the augmented MILP is run on yearly horizons, unlike the simple MILP

[6] Energy storages are exonerated from that tax as from 01/01/2018, which in paper is then treated as 0 €/MWh onward.

Sets
H the set of hours h in the year

Variables
$c_h\ \forall\ h$, the charging rate at hour h
$d_h\ \forall\ h$, the discharging rate at hour h
$b_h\ \forall\ h$, binary variables for choosing the operation mode
$s_h\ \forall\ h$, the storage energy level at hour h
f_{base}, the total EUR amount of all non-capped grid fees
f_{cap1}, the EUR amount of the capped grid fee F5
f_{cap2}, the EUR amount of the capped grid fee F7
x_i, with $i = 1, 2, ..., 5$, binary variables to select the discount on F5
y_j, with $j = 1, 2$, binary variables to have fee caps binding or not

Constants
$M = 10^7$
$N = 10^8$

Parameters
$P_h\ \forall\ h$, the day-ahead market prices in €/MWh
η, the storage round-trip efficiency
S_{max}, the storage duration
K, the storage installed power in MW
R_d, the grid-fee rate F15 in discharging mode
R_c, the sum of non-capped grid-fee rates in charging mode
R_{cap1}, the base capped grid-fee rate F5 in charging mode
R_{cap2}, the base capped grid-fee rate F7 in charging mode

Objective function

$$\max \sum_h P_h(d_h - c_h) - f_{base} - f_{cap1} - f_{cap2} \tag{7}$$

Constraints

$$0 \leq d_h \leq b_h \qquad \forall\ h$$
$$0 \leq c_h \leq (1 - b_h) \qquad \forall\ h$$
$$0 \leq s_h \leq S_{max} \qquad \forall\ h$$
$$s_{h+1} = s_h - d_h/\sqrt{\eta} + c_h\sqrt{\eta} \qquad \forall\ h$$
$$s_0 = S_{max}/2 = s_{\mathrm{card}(H)}$$
$$0 \leq f_{base} \tag{8}$$
$$0 \leq f_{cap1} \leq 250000/K \tag{9}$$
$$0 \leq f_{cap2} \leq 252750/K \tag{10}$$
$$R_d \sum_h d_h + R_c \sum_h c_h = f_{base} \tag{11}$$
$$0 - M(1 - x_1) \leq K \sum_h c_h \leq 20 + M(1 - x_1) \tag{12}$$
$$20 - M(1 - x_2) \leq K \sum_h c_h \leq 50 + M(1 - x_2) \tag{13}$$
$$50 - M(1 - x_3) \leq K \sum_h c_h \leq 1000 + M(1 - x_3) \tag{14}$$
$$1000 - M(1 - x_4) \leq K \sum_h c_h \leq 25000 + M(1 - x_4) \tag{15}$$
$$25000 - M(1 - x_5) \leq K \sum_h c_h \tag{16}$$
$$x_1 + x_2 + x_3 + x_4 + x_5 = 1 \tag{17}$$
$$1.00\, R_{cap1} \sum_h c_h - N(2 - x_1 - y_1)/K \leq f_{cap1} \tag{18}$$
$$0.85\, R_{cap1} \sum_h c_h - N(2 - x_2 - y_1)/K \leq f_{cap1} \tag{19}$$
$$0.80\, R_{cap1} \sum_h c_h - N(2 - x_3 - y_1)/K \leq f_{cap1} \tag{20}$$
$$0.75\, R_{cap1} \sum_h c_h - N(2 - x_4 - y_1)/K \leq f_{cap1} \tag{21}$$
$$0.55\, R_{cap1} \sum_h c_h - N(2 - x_5 - y_1)/K \leq f_{cap1} \tag{22}$$
$$1.00\, R_{cap2} \sum_h c_h - N(2 - x_1 - y_2)/K \leq f_{cap2} \tag{23}$$
$$0.85\, R_{cap2} \sum_h c_h - N(2 - x_2 - y_2)/K \leq f_{cap2} \tag{24}$$
$$0.80\, R_{cap2} \sum_h c_h - N(2 - x_3 - y_2)/K \leq f_{cap2} \tag{25}$$
$$0.75\, R_{cap2} \sum_h c_h - N(2 - x_4 - y_2)/K \leq f_{cap2} \tag{26}$$
$$0.55\, R_{cap2} \sum_h c_h - N(2 - x_5 - y_2)/K \leq f_{cap2} \tag{27}$$
$$(250000 - N * y_1)/K \leq f_{cap1} \tag{28}$$
$$(252750 - N * y_2)/K \leq f_{cap2} \tag{29}$$

Figure 2: Augmented MILP maximizing the arbitrage value of a price-taker energy storage, with perfect foresight of prices, facing Belgian TSO grid-fees.

Applicability	Fee label	2016	2017	2018	2019	2020	2021
Belgium	F1. Tariff for the operation of the electric system	0.4924	0.4968	0.4978	0.4897	0.9074	0.9268
	F2. Tariff for the power reserves and black start	0.9165	1.1189	1.3710	1.5626	0.6879	0.6929
	F3. Tariff for market integration	0.3492	0.3604	0.3870	0.3946	0.3682	0.3667
	F4. Tariff for public service obligation for offshore wind integration	0.0629	0.0785	0.1518	0.1613	0.1188	0.0840
	F5. Tariff for public service for financing federal green certificates	3.8261	4.3759	5.1601	7.2875	9.0141	11.6852
	F6. Tariff for financing strategic reserve	0.9972	0.1902	0.4298	0.0000	0.0000	0.0510
	F7.[6] Tax and overcost: federal contribution	3.0033	3.3705	3.4439	3.3461	3.1428	3.4700
Flanders	F8. Tariff for supporting renewables and cogeneration	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	F9. Tariff for promoting rational use of energy	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	F10. Overcost and tax for pylons and tranches	0.1000	0.1160	0.1160	0.0933	0.1441	0.4445
Wallonia	F11. Tariff for financing renewables: first component	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	F12. Tariff for financing renewables: second component	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	F13. Overcost and tax for use of public domain	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Brussels	F14. Levy occupation road network	3.2530	3.3005	3.3819	3.4642	3.5084	3.5248

(a) Offtake grid fees (€/MWh).

Applicability	Fee label	2016	2017	2018	2019	2020	2021
Belgium	F15. Tariff for the power reserves and black start	0.9644	0.9644	0.9644	0.9644	0.6169	0.6169

(b) Injection grid fees (€/MWh).

Table 2: Variable offtake and injection grid fees on Elia 380/220/150/110 kV networks in Belgium.

		Fee F5	Fee F7[6]	x_i	Eq.
Offtake (MWh/year)	0-20	0%	0%	x_1	(12)
	20-50	-15%	-15%	x_2	(13)
	50-1000	-20%	-20%	x_3	(14)
	1000-25000	-25%	-25%	x_4	(15)
	> 25000	-45%	-45%	x_5	(16)
Yearly cap of the fee		250 k€	272.75 k€		
y_i		y_1	y_2		
Eq.		(28)	(29)		

Table 3: Discount percentages and caps on grid fees F5 and F7 listed in Table 2.

which is run on rolling horizons of 7 days. However, for the cases examined in this paper, the difference in arbitrage value between the yearly and 7-day rolling horizons is found to be negligible. Therefore, utilizing yearly horizons for the augmented MILP does not compromise the accuracy of our valuation results.

3.3. Input data

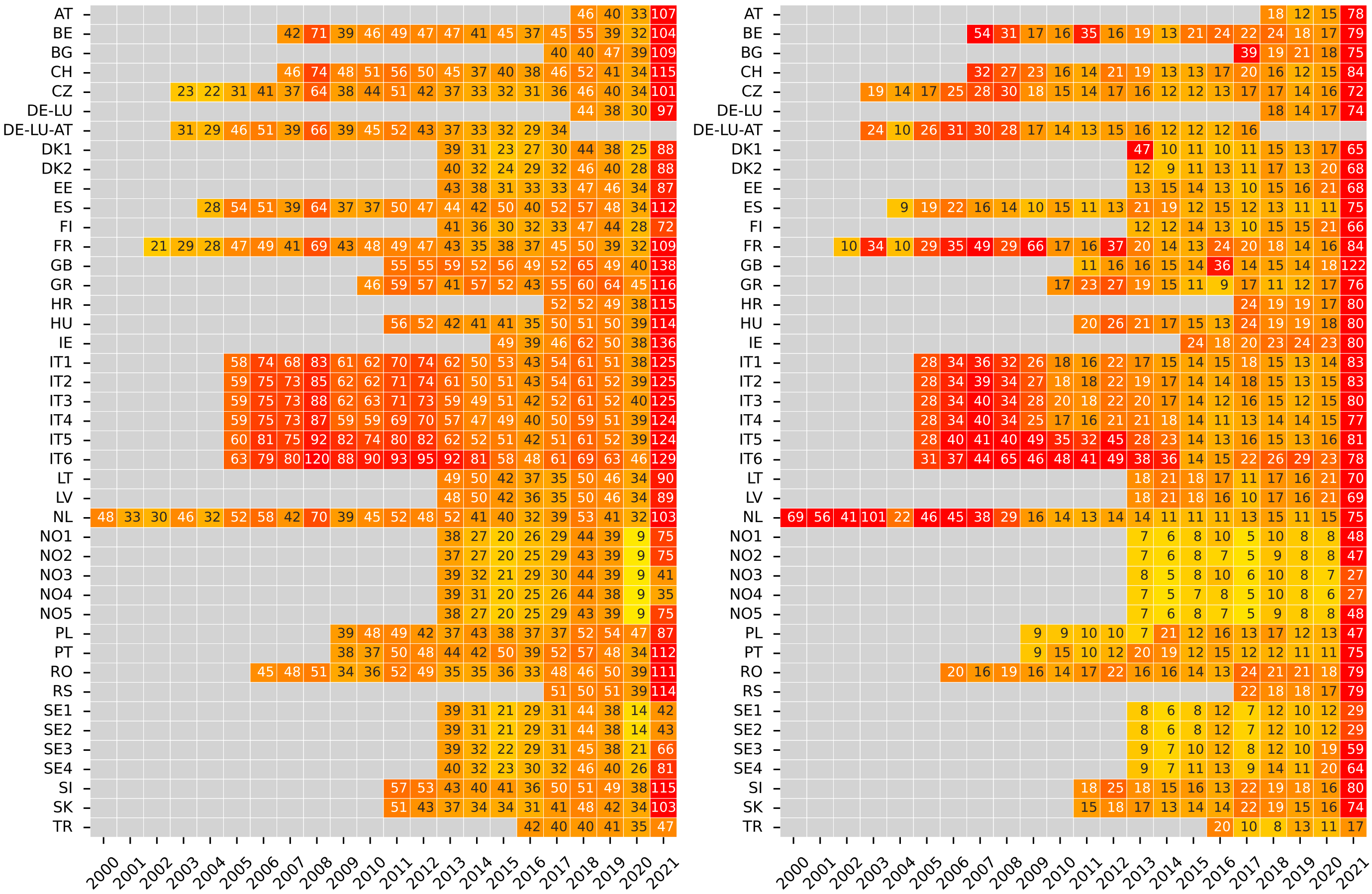
The two models take as input the parameters described in Figure 1, i.e. the round-trip efficiency, η, the storage duration, S_{max} and a price series. The price series used in our analysis are historical series of hourly DAM prices that were recovered from the different power exchanges, from as far as possible in the past until 2021.

Figures 3a and 3b show two of main characteristics of the hourly price series, namely their yearly average and yearly volatility. Besides the exceptional character of the year 2021, which was impacted by the war in Ukraine and the subsequent European gas crisis, the Figures highlight the very diverse nature of our dataset, which shows significant average price and volatility variations across years and regions. Countries like Norway, and to a lesser extend Sweden, clearly stand out with very stable hourly prices, which are respectively the result of the almost exclusive and the high share of hydro, with big reservoirs, in their electricity mix. While the diversity of our dataset of hourly DAM prices has obviously some roots in the diversity of the regional electricity mixes, which are shown in Figure 4, other factors are also at play as discussed further in Section 5.

For the specific cases of Great Britain (GB), Bulgaria (BG) and Turkey (TR), the historical DAM price series are retrieved in local currency, and converted in EUR (€) using the historical daily exchange rates published by the European Central Bank (ECB) European Central Bank (2021). While electricity is traded every single day on DAMs, currencies are exchanged on business days only. Therefore, missing days in the exchange-rate time series were filled in with the exchange rate on the next business day. This way of doing is in line with the idea of a European business hedging its DAM revenue as soon as it can, i.e. converting it to EUR on the business day itself, otherwise on the next business day.

3.4. Model implementation

Both the simple MILP and the augmented MILP are coded in *Python* 3.9, using *PuLP* 2.6 as MILP



(a) Yearly average of hourly DAM prices (€/MWh)

(b) Yearly volatility of hourly prices (€/MWh)

Figure 3: Yearly average and volatility of hourly prices in the studied bidding zones.

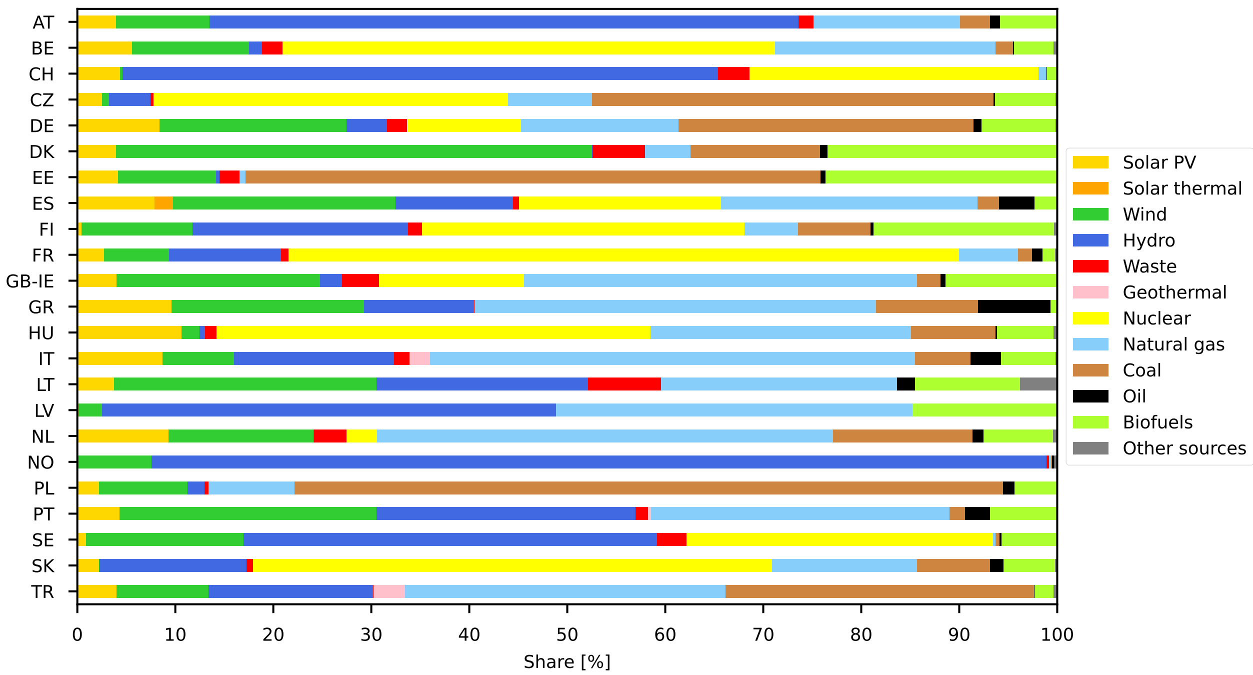


Figure 4: Electricity generation by source in 2021, as reported by the International Energy Agency (IEA) (2022).

modeller and *CPLEX* 22.1 as solver. The two models are solved several times, with different inputs, each time with a relative gap tolerance of 10^{-3} for the solver to stop. The solving process is speeded up by taking advantage of the 4 cores of the hosting laptop.

We study 43 bidding zones, each with several years of historical DAM prices, which gives a total of 484 zone-years, i.e. slightly more than an average of 10 years of data per zone. For each of these 491 zone-years, a valuation is made for varying round-trip efficiencies and storage durations. The round-trip efficiency takes 11 different values, varying from 50% to 100% by steps of 5 percentage points, while the storage duration takes 10 different values, varying from 1 to 10 hours, by steps of 1 hour. This leads to 484 x 11 x 10 = 53 240 valuations. For each of those yearly valuations, the rolling approach explained in Section 3.1 is such that the simple MILP is run close to 365 times.

The augmented MILP is then run to put in light the impact of grid fees on arbitrage value. For varying round-trip efficiencies and storage durations, the model is run for the specific case of Belgium and for 6 years from 2016 to 2021, for 3 different storage sizes and differentiating for the 3 Belgian regions. This means 11 x 10 x 6 x 3 x 3 = 5 940 runs of the augmented MILP, one per valuation.

4. Results

Given the extensive nature of the results obtained by running the models, only some of them are presented in the paper. The complete scope of results is made available to the reader in the form of an *Excel* file.

4.1. Temporal evolution and geographical disparities

Figure 5 shows the results obtained by running the simple MILP of Figure 1 with as input the historical DAM prices, while the round-trip efficiency and the storage duration are kept constant, respectively at 75% and 5 hours. The results highlight significant variations in arbitrage value, between countries and over time.

The heat map of Figure 5a shows the historical yearly arbitrage value of our standard energy storage on every bidding zone in Europe, and for as many years as we could go back in time. By displaying on a map of Europe the average yearly value over the four-year period 2018-2021, Figure 5b emphasizes the recent geographical disparities between countries. Besides, Figure 5b displays the existing storage facilities reported by Geth et al. (2015) and having a rated power of at least 100 MW in discharge mode.

4.1.1. Temporal evolution of storage value from arbitrage

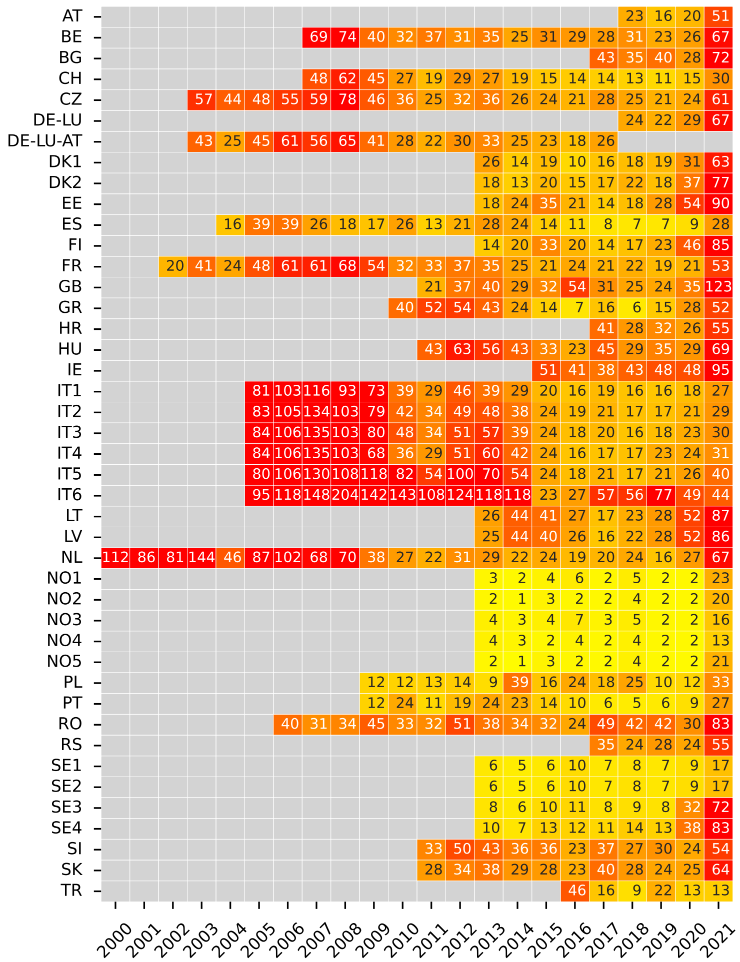
Looking at Figure 5a, it is striking to see the how volatile is storage value from arbitrage. In many countries, arbitrage value decreased significantly from the highs of the years around 2009 and before, to the lows of the years 2015 to 2020, before surging in 2021 following the European gas crisis. In some bidding zones, and depending on the years which are being compared, the ratio of highs to lows largely exceeds 2. This observation holds for Belgium (BE), Switzerland (CH), Czech Republic (CZ), Germany, Luxembourg and Austria (DE-LU-AT vs DE-LU and AT), Spain (ES), France (FR), Greece (GR), Hungary (HU), Italy (IT1-IT6) and the Netherlands (NL). Italy is a good example with bidding zones IT1-IT5 showing a storage value from arbitrage close to or exceeding 125 k€/MW/year in 2007, while it barely reaches 25 k€/MW/year over 2018-2020, which gives a ratio of 5. Higher ratios can however be found, e.g. 6 in Finland (FI, 2021 to 2017) and Great Britain (GB, 2021 to 2011), and up to 12 in Sweden (SE4, 2021 to 2014).

Other countries exhibit a significant increase in arbitrage value already starting in 2020, and which continued in 2021. This is the case for Denmark (DK1 and DK2), Estonia (EE), Finland (FI), Greece (GR), Lithuania (LT), Latvia (LV) and Sweden (SE3 and SE4 only).

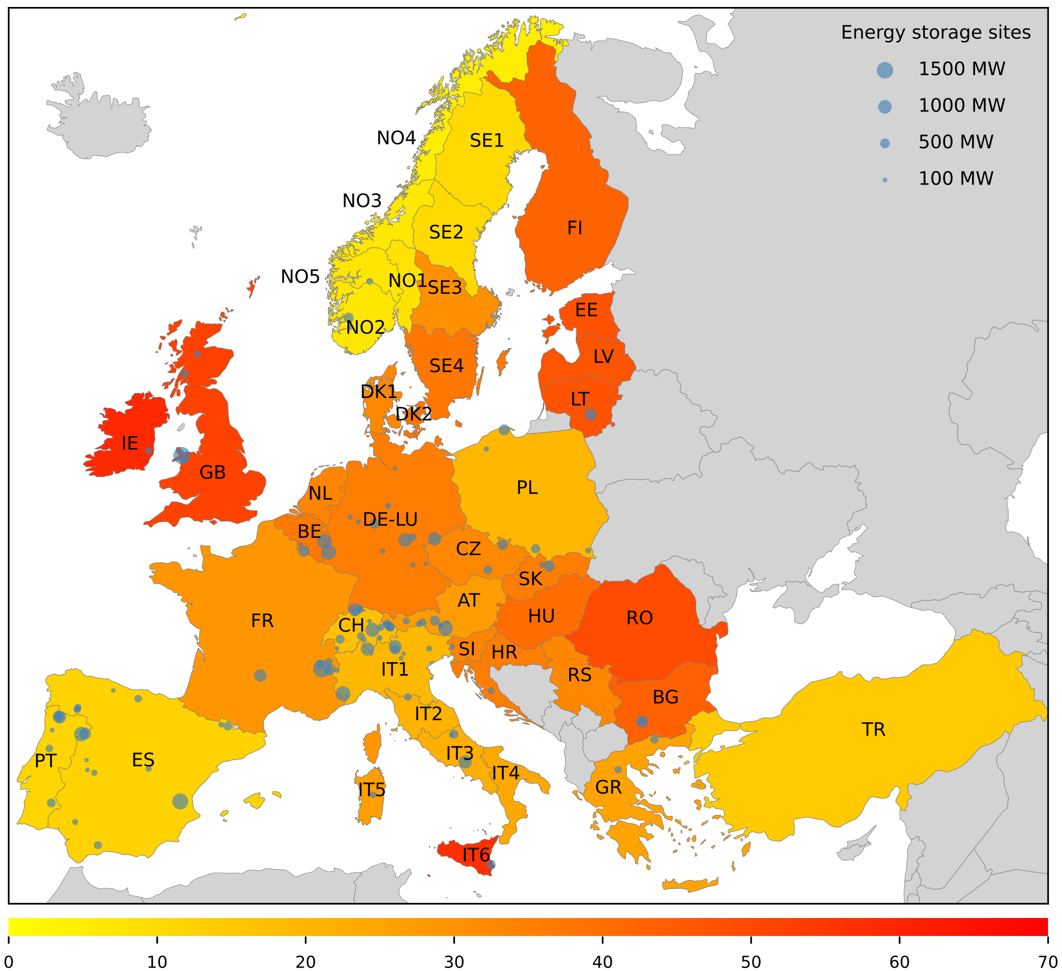
Overall, most countries for which we could go back 10 years or more in time show a clear decline in arbitrage value from the highs of 2009 and before, to the lows of the recent years, before surging again in 2021. What is remarkable is as much the high volatility of arbitrage value as the fact that it is observed in a wide range of countries.

4.1.2. Geographical disparities in storage value from arbitrage

Figures 5a and 5b highlight the significant geographical disparities in storage value from arbitrage. Some regions show very low value, around 10 k€/MW/year or lower. This is especially the case of Norway (NO1-NO5), the country with the lowest value, but also Sweden, SE1-SE2 and depending on



(a) Yearly arbitrage value (k€/MW/year)



(b) Average yearly arbitrage value over 2018-2021 (k€/MW/year)

Figure 5: Historical value of day-ahead market arbitrage (k€/MW/year) of a perfectly forecasting price-taker storage with 75% round-trip efficiency and 5-hour duration.

the year, SE3-SE4, as well as Spain (ES) and Portugal (PT) in the years 2016 to 2020. Although these countries show a clear arbitrage value increase in 2021, they remain well below high-value countries.

In 2020, the top 3 countries in term of arbitrage value were Estonia (EE), Latvia (LV) and Lithuania (LT) with respectively 54, 52 and 52 k€/MW/year. However, looking at the average value over 2018 to 2020, the two regions standing out are Sicily (IT6) and Ireland (IE) with respectively 61 and 46 k€/MW/year. In 2021, the European gas crisis redistributed the cards with the highest value country being Great Britain (GB).

Overall, Figure 5a highlights that geographical disparities in storage value from arbitrage decreased over time until 2020, before increasing again in 2021.

4.2. Impact of round-trip efficiency and duration on storage value from arbitrage

As explained in subsection 3.4, the sensitivity of arbitrage value with respect to round-trip efficiency and storage duration is investigated by varying these two parameters. Figure 6 shows the results of this analysis in the form of iso-value contour plots, for the years 2020 and 2021.

Not surprisingly, for every single bidding zone, arbitrage value monotonously increases with both the round-trip efficiency and the duration. As storage duration increases, the iso-lines get more and more horizontal, although still downward sloping, reflecting the positive but decreasing marginal value of storage duration. As from a few hours of storage, somewhere between 3 and 5 hours depending on the country, the value of additional storage duration becomes negligible. The opposite is true for the round-trip efficiency. As efficiency increases, the iso-lines get closer and closer to one another, indicating an increasing marginal value of the round-trip efficiency. At low round-trip efficiencies, close to 50%, storage value from arbitrage is significantly lower as compared to the value at a classical 75% efficiency. Although the impact of round-trip efficiency and storage duration on arbitrage value were, to some extent, already known, they are for the first time observed and quantified on a very wide basis, in many different countries, each with its own specificities, and on a large range of years, round-trip efficiencies and storage durations.

Among all the countries in Figure 6, Norway stands out with a 2020 arbitrage value systematically below 5 k€/MW/year, except in the region of very high round-trip efficiency, close to 100%, and high storage duration, where the value is somewhat higher although not exceeding 10 k€/MW/year. For the other countries showing a low value of storage from arbitrage, e.g. Spain, Portugal, Switzerland, and to some extent Sweden, Figure 6 shows that the value remains limited even at 100% round-trip efficiency and 10-hour storage duration. This result shows that storage value from arbitrage is not just about round-trip efficiency and storage duration, but it is also and above all inherently linked to the price dynamics at play in the local DAM.

Looking at 2021, were arbitrage value is much higher, the iso-lines are noticeably closer to one another, underlying the increased impact of round-trip efficiency on storage value.

4.3. Storage value from arbitrage versus price dynamics

The storage value from arbitrage computed in this paper is directly related to the price series that are used as input to our MILP model, and although Figures 3a and 3b give a taste of the price disparities between countries, we want to better understand the link between arbitrage value and price dynamics. Figure 7 shows the results of Figure 5a from a different point of view, relating arbitrage value to the yearly average and yearly volatility of the underlying hourly price series. A distinction is made between the years up to 2014, the ones between 2015 and 2020, and the year 2021. As we move on the graph from bottom to top, we go from low-value yellow points to higher-value orange and red points. While as we move from left to right, there is no clear trend in arbitrage value. There is however a region of high-price and high-volatility points, associated to the year 2021 and the years up to 2014. Overall, between yearly average and yearly volatility of hourly prices, the latter is clearly the determining factor of storage value from arbitrage. There is however an implicit economic trade-off related to price volatility. Higher price volatility increases the potential for price arbitrage, while it may alter the ability to forecast prices accurately and capture significant shares of the arbitrage potential. Besides, price volatility evolves within the year and so does the ability to forecast prices.

Fuelling the yearly volatility of hourly prices, price spikes clearly contribute to arbitrage value. Figure 8 shows the historical occurrences of hourly DAM

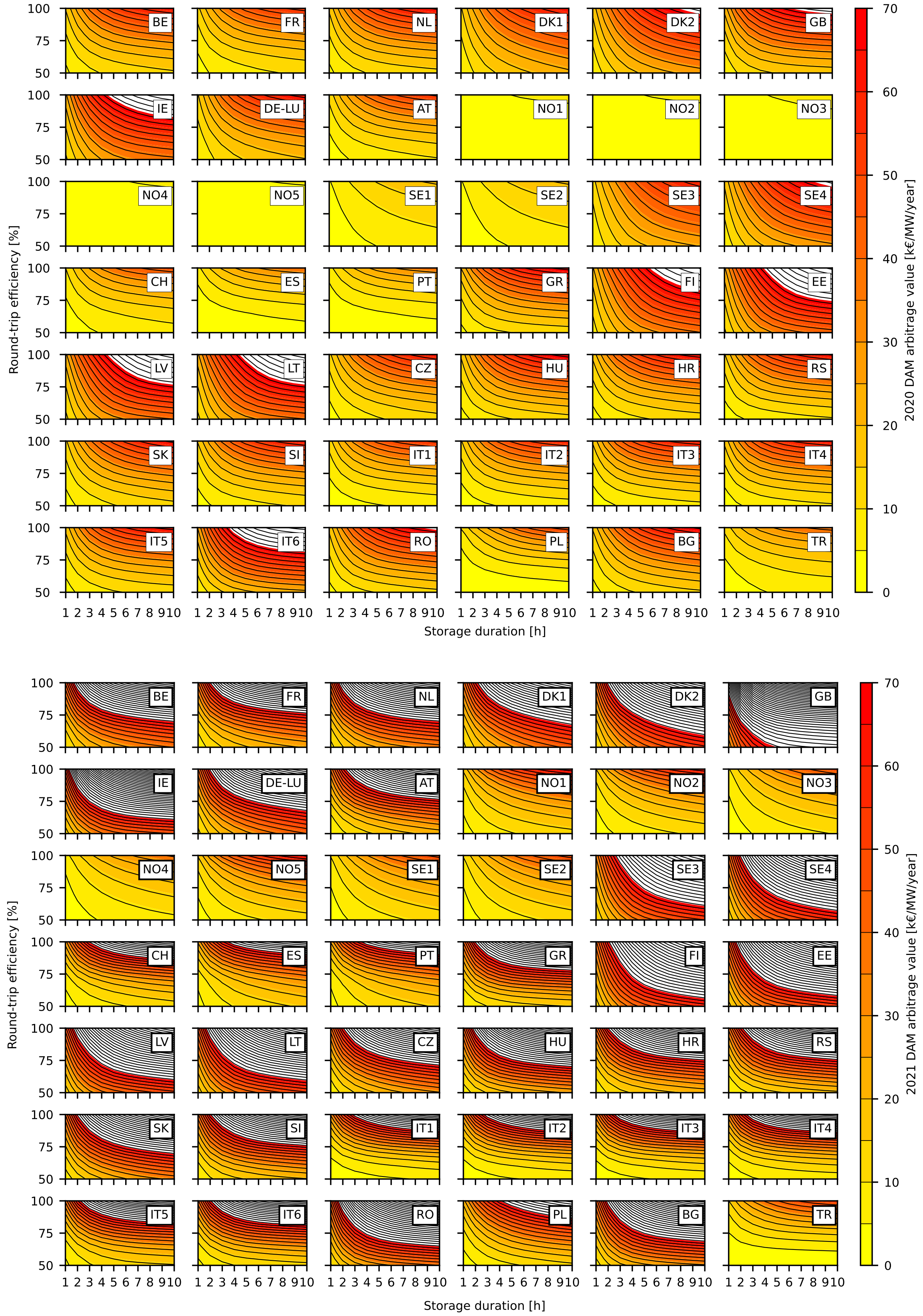


Figure 6: 2020 (top) and 2021 (bottom) sensitivity of arbitrage value to round-trip efficiency and storage duration.

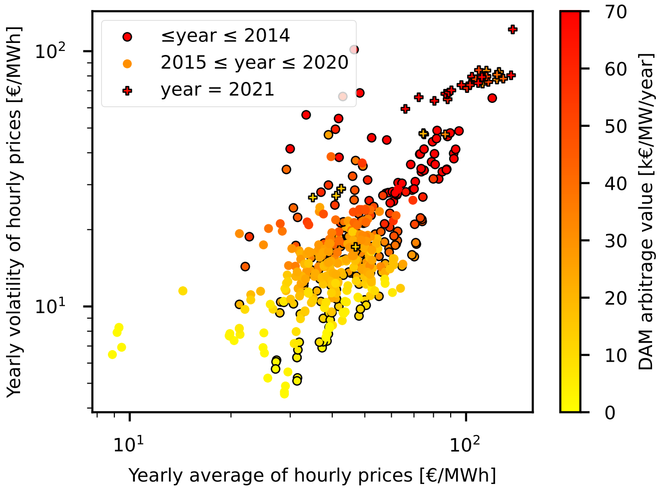


Figure 7: Storage value from arbitrage versus yearly average and yearly volatility of hourly prices.

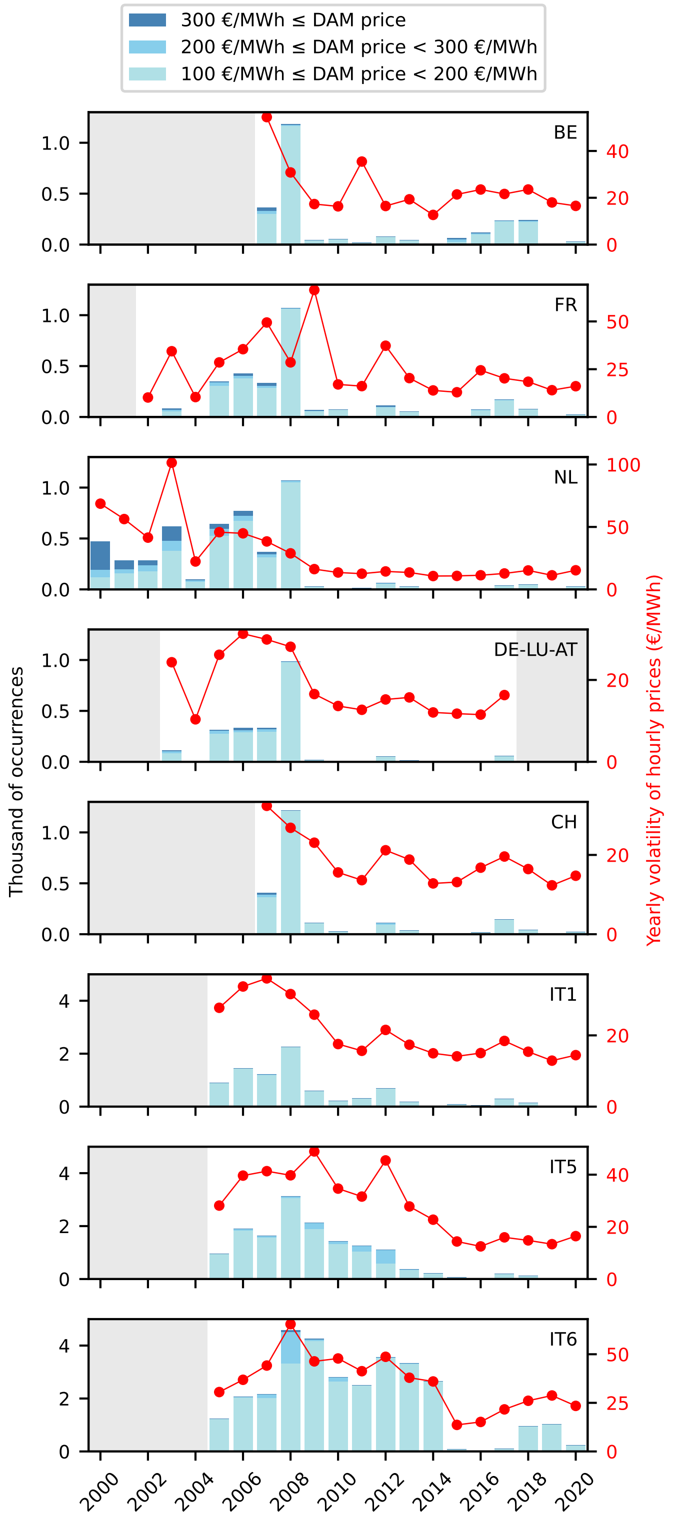


Figure 8: Long-term evolution of hourly day-ahead market price spikes (left axis) and volatility (right axis).

price spikes in several bidding zones, and highlights a clear trend of decreasing price spikes occurrences.

Finally, Figure 9 shows the long-term evolution of the yearly average and yearly volatility of hourly day-ahead market prices. It can be seen from the Figure that the last 7 years, except 2021, are characterized by the convergence of the different day-ahead markets toward a region of low prices and low volatility. This phenomenon is certainly the result of several contributors, with not only the coupling of day-ahead markets discussed in Section 2, but also low fuel prices and the increasing penetration of low marginal-cost renewable generation.

4.4. Storage value from arbitrage versus load factor

A storage derives its arbitrage value from price spreads, which can happen from time to time or frequently, and which can be just sufficient for the storage to be at the money, or instead much higher, making the storage highly profitable on a few occasions. To better understand how arbitrage value is generated, Figure 10 shows the results of Figure 5a under a different angle, and for two different round-trip efficiencies, emphasizing the relation between arbitrage value and load factor. The load factor, LF, which is the number of charge and discharge hours divided by the amount of hours in the year, is computed from the optimal dispatch:

$$LF = \frac{1}{card(H)} \sum_h (c_h + d_h)$$

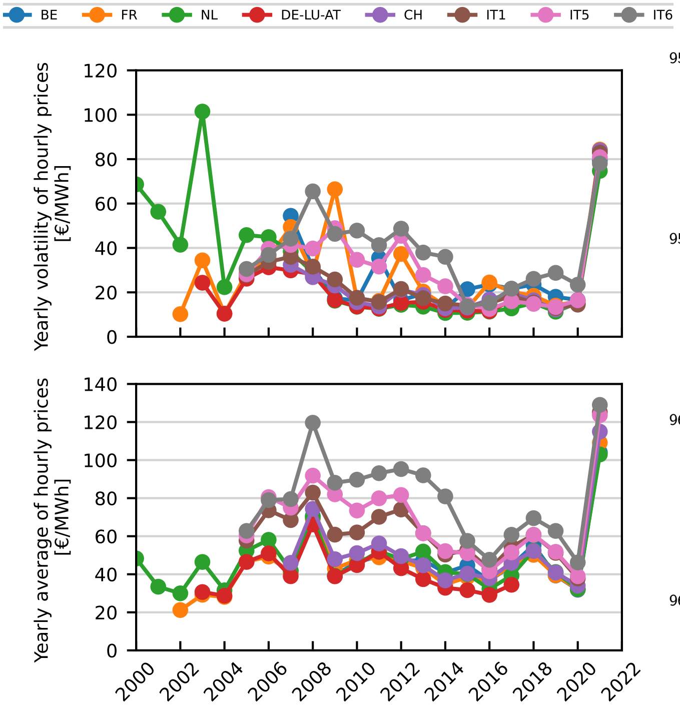


Figure 9: Long-term evolution of day-ahead market prices.

Again, to isolate very high arbitrage values of the past, a distinction is made between years before 2014 and the ones since 2015.

Looking more specifically at the 75% round-trip efficiency case, for the years up to 2020, a linear trend emerges between arbitrage value and load factor, for values up to 23 k€ /MW/year with a corresponding load factor close to 45%. Clearly, low arbitrage values are associated with low load factors, or, putting it differently, energy storages in low-value countries rarely operate. At higher arbitrage values, the load factor is at least 35% and the linear relation between arbitrage value and load factor disappears. The load factor is always below 60%, except in two instances where slightly higher numbers are observed. Interestingly, although the year 2021 shows higher arbitrage value, the associated load factors remain in the same range as for the years before.

Both arbitrage value and the load factor collapse as the round-trip efficiency decreases from 75% down to 50%.

4.5. Impact of grid fees on arbitrage value and load factor

The MILP of Figure 2 is solved for several sets of parameters, including varying round-trip efficiencies and storage durations. The prices used as input are the yearly series of realized hourly DAM prices in Belgium, for the 6 consecutive years from 2016 to 2021. The grid tariffs are the corresponding historical tariffs in the three Belgian regions, thus including both the country-level and the region-specific components, as detailed in Tables 2 and 3. Since the structure of the grid tariff introduces a storage size sensitivity, the same analysis is performed for three different storage sizes, 25 MW, 100 MW and 1000 MW. Some of the results are given in Figure 11, in the form of a bar plot. The very top of each bar corresponds to the arbitrage value that was previously computed neglecting grid fees, let us call it the gross arbitrage value, and which is given by the objective function of the simple MILP, Equation (1). As grid fees are introduced, only a share of the gross arbitrage value goes into the hands of the storage owner. This share is the net arbitrage value, and it is given by the objective function of the augmented MILP, Equation (7). The difference between gross and net arbitrage value is explained by i) missed opportunities and ii) grid fees to be paid. The missed opportunities are the result of the modified optimal dispatch arising from the price-signal distortion introduced by grid fees. The modified optimal dispatch has indeed a reduced number of running hours, since some price spreads that were otherwise profit-making, are not profitable anymore when grid fees are taken into account. For the remaining running hours, an amount $f_{base} + f_{cap1} + f_{cap2}$ of grid fees has to be paid to the grid operator, which leaves the storage owner with a net arbitrage value as indicated in Figure 11.

For the years 2016 to 2020, and for a 75% round-trip efficiency, the results of Figure 11 show that grid fees reduce arbitrage value by 20% to 50% as compared to the case without grid fees, with the 20% corresponding to the 2020 1000-MW case in Flanders and Wallonia, and the 50% corresponding to the 25 MW case in Brussels. Overall, and as expected given the tariff degressivity and cap on fees F5 and F7, the smaller the storage, the larger the negative the impact of grid fees on storage value from arbitrage. Clearly, our findings show that the non-linearity introduced by the grid-fee structure prevents a level playing field between small and large energy storage. This is an important aspect that might be considered by policy-makers for potential changes in the grid-tariff design.

At 50% round-trip efficiency, a similar decrease in arbitrage value is observed percentage-wise. For

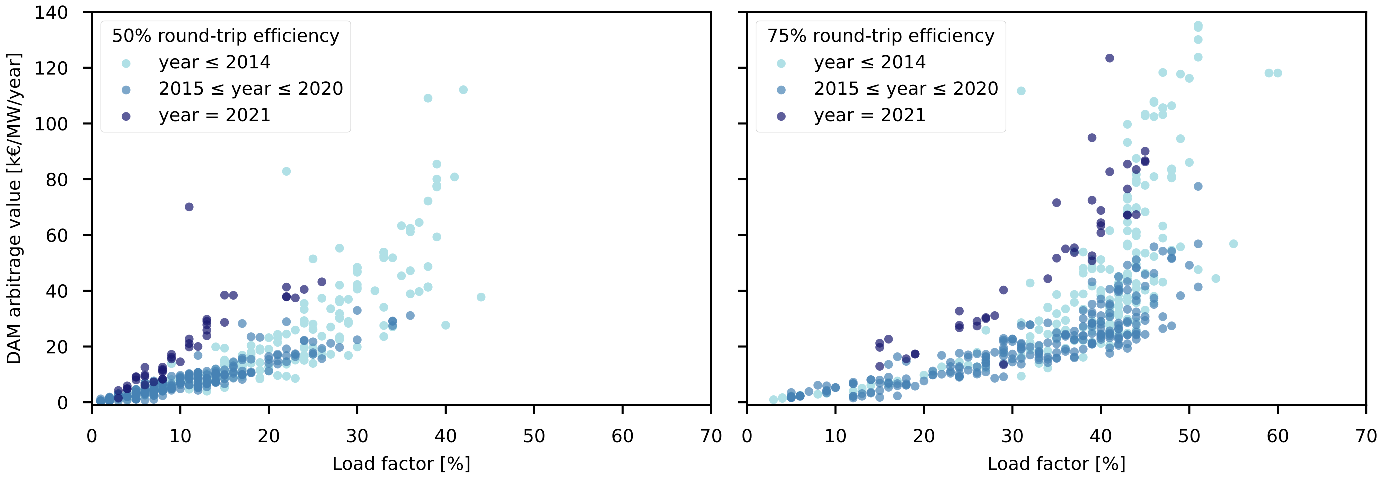


Figure 10: The link between arbitrage value and load factor. 50% (left), 75% (right) round-trip efficiency and 5-hour duration.

the year 2021, showing much higher value, grid fees reduce the gross arbitrage value by a smaller percentage.

Regarding regional disparities within Belgium, Brussels is the region with the lowest storage value from arbitrage. This is due to the Brussels-specific fee, F14, being higher than the other regional fees.

Looking in more details at the missed opportunities, these are most of the time bigger for the 25-MW storage than for the 1000-MW storage. This is again due to the degressivity and the cap of grid fees F5 and F7, exposing the two storages to different effective price signals, which results in different optimal dispatch.

Although missed opportunities are rather low, they are associated with dramatic decreases of the load factor, as emphasized in Table 4. For the years 2016 to 2020, and for a storage with 75% round-trip efficiency, the load factor decreases by 8 to 27 percentage points as compared to the case without grid fees, where it is above 40%. The reduced load factor is associated with pairs of charging/discharging hours that are shifted by grid fees, from just in the money to just out of the money. As already discussed previously, the load factor collapses as the round-trip efficiency decreases from 75% to 50%. At 50% round-trip efficiency, the load factor falls between 10% and 15%, which is further decreased by 2 to 10 percentage points in the cases with grid fees.

Finally, among the 75% round-trip efficiency cases, no matter the storage size, the year, or the region within Belgium, it is found that the resulting optimal dispatch always implies a yearly charging volume of at least 25000 MWh. In these cases, the storage always benefits from the degressivity in the F5 and F7 tariffs, as shown in Table 3, on top of eventually benefiting from the caps. In the specific cases of a 25-MW storage with 75% round-trip efficiency in Brussels (2016 to 2020), in Flanders (2019), and in Wallonia (2019), the yearly charging volume is precisely 25000 MWh. This is the sign that some loss-making arbitrage operations were done with the sole purpose of reaching the yearly 25000 MWh charging volume, in order to benefit from a reduced grid tariff. The same phenomenon is observed for the 100 MW storages at 50% round-trip efficiency, although not necessarily for the same years and regions.

Operationally speaking, energy storages in Belgium might well base their DAM bidding on the assumption that they will reach a yearly charging volume of 25000 MWh. Our findings highlight that as the end of year approaches, while the year-to-date charging volume is less than 25000 MWh, energy storages might consider loss-making arbitrage operations with the sole purpose of reaching the yearly 25000 MWh offtake threshold.

5. Discussion

Energy storage value from arbitrage is intrinsically linked to the price dynamics in each bidding zone, which are themselves driven by several factors, such as the generation mix and its adequacy with respect to the load, the presence of energy storage, intermittent renewable generation and the regulatory framework around it, interactions with neighbouring countries through cross-border capacities, but also

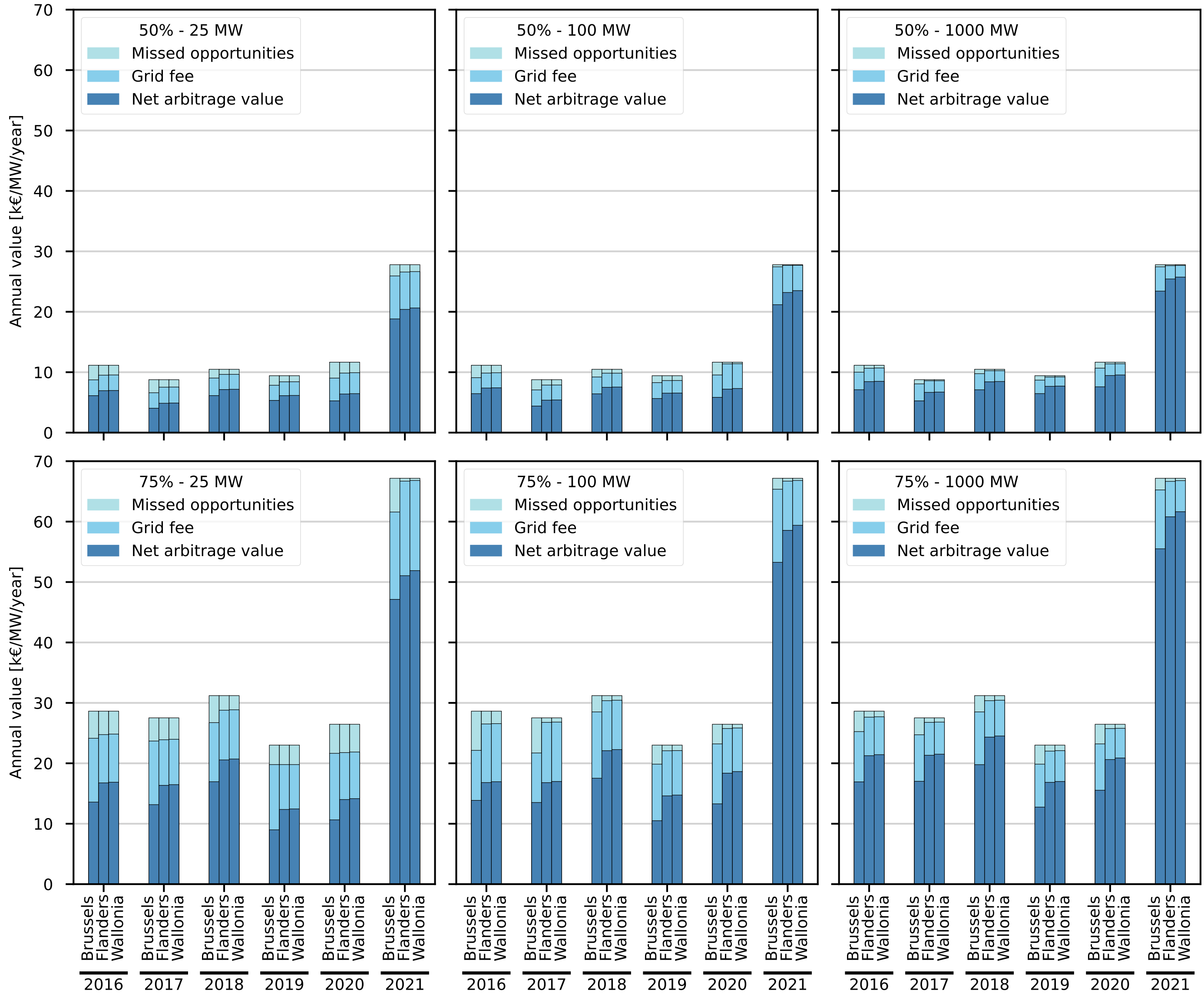


Figure 11: Impact of variable grid fees and storage size on storage value from arbitrage in Belgium - 50% (top), 75% (bottom) round-trip efficiency and 5-hour duration.

Year		2016			2017			2018			2019			2020			2021		
Region		B	F	W	B	F	W	B	F	W	B	F	W	B	F	W	B	F	W
50% round-trip efficiency	Without grid fees	14	14	14	11	11	11	10	10	10	10	10	10	15	15	15	13	13	13
	With grid fees - 1000 MW	6	9	9	7	9	9	6	8	8	5	7	7	8	11	11	11	12	12
	With grid fees - 100 MW	4	6	6	4	6	6	5	6	6	4	5	5	6	11	11	11	12	12
	With grid fees - 25 MW	4	5	5	4	5	5	5	6	6	4	5	5	5	6	6	8	9	9
75% round-trip efficiency	Without grid fees	43	43	43	42	42	42	40	40	40	40	40	40	47	47	47	43	43	43
	With grid fees - 1000 MW	23	32	32	23	32	32	24	31	32	20	29	29	24	36	37	31	37	38
	With grid fees - 100 MW	16	27	27	16	32	32	24	31	32	20	29	29	24	36	37	31	37	38
	With grid fees - 25 MW	20	22	22	20	21	21	20	25	25	20	20	20	20	20	21	23	37	38

Table 4: Storage load factor [%] in Belgium, with and without grid fees - 50% (top) and 75% (bottom) round-trip efficiency, 5-hour duration.

Country	Installed PHES	Average load	Ratio
AT	4051 MW	7112 MW	57%
CH[7]	2291 MW	7117 MW	32%
ES	6358 MW	28323 MW	22%
PT	1279 MW	5661 MW	23%

Table 5: Ratios of installed PHES to average load, based on Geth et al. (2015); European Network of Transmission System Operators (ENTSO-E) (2022).

the level of fuel prices, and many more. While it is not in the scope of this paper to carry out a quantitative analysis on the combined impact of these drivers on DAM prices, it is insightful to discuss them individually.

On the impact of the generation mix, good examples are, as already mentioned in Section 3.3, Norway and Sweden. Between 2013 and 2020, the share of hydro in the Norwegian electricity mix was as high as 90% to 95%, while on the same period, the share of nuclear and hydro generation in Sweden remained both close to 40% International Energy Agency (IEA) (2022). These peculiar generation mixes, mostly composed of low marginal-cost dispatchable technologies, are the biggest driver of the very stable DAM prices and the subsequent low arbitrage value observed in these two countries.

A stabilizing factor of day-ahead prices is of course the presence of energy storages. In that regard, Austria, Switzerland, and the Iberian Peninsula clearly stand out, with ratios of installed PHES to average annual load above 20%, as indicated in Table 5. In the other countries, the ratio barely reaches 10%. Interestingly, arbitrage value is higher in Switzerland and Austria than in Spain and Portugal, although the former two countries have higher ratios of installed PHES to average load. This counter-intuitive fact should remind the reader that existing energy storages are only one of the many factors impacting price volatility. From an interconnection point of view, Spain and Portugal are more isolated than Austria and Switzerland, which limits the exportability of their local flexibility.

Another driver of day-ahead prices is the penetration of intermittent renewable generation. In Ketterer (2014), the authors build a ARX-GARCHX model and show that over the period 2006 to 2011, German wind power, which at the time already exceeded 20 GW of installed capacity, decreased the level of the Phelix Day Base[8], while it increased its volatility.

Based on data respectively from 2012 to 2014, and 2010 to 2014, Rintamäki et al. (2017) builds a SARMA model with exogenous variables and finds that higher wind penetration increases the daily volatility of hourly prices in Germany, while it decreases it in Denmark. According to the authors, this contrasting observation would be due to Denmark having access, through its cross-border capacities, to the flexible hydro generation of the Nordic countries, whereas compared to the size of its power system, Germany has both limited cross-border capacities and limited flexible generation. Besides, the difference in wind profile in the two countries would also play a role. In Denmark both peak and off-peak hourly prices are found to decrease nearly equally due to wind power generation, while in Germany there is an increase in price volatility because of greater wind power output during the more sensitive off-peak hours.On the contrary to wind, solar power is found to decrease the daily volatility of hourly prices in Germany, as it is produced only during peak hours, thereby pushing high hourly peak-prices down.

The impact of renewables on day-ahead prices is also function of the regulatory framework in place, with for example feed-in tariffs incentivizing renewable producers to bid a negative price, which in turn increases day-ahead price volatility. In Spain, Ciarreta et al. (2020) argues that the abolishment of the feed-in tariff and feed-in-premium schemes in 2013, and the establishment of a more market-oriented policy for the support of renewables, led to a decrease in price volatility. In a similar register but this case in Germany, Frondel et al. (2022) shows that the introduction of the German market premium scheme for the promotion of green electricity, as an alternative to feed-in tariffs, decreased the number of hours with negative prices by some 70%.

When it comes to cross-border capacities and interactions with neighbouring countries, an interesting analysis is the one performed on the Swiss electricity market in Keles et al. (2020). The authors show that the Swiss electricity prices are mostly determined by cross-border trade. In the summer, the Swiss electricity prices correlate strongly with the one of Germany,

[7]Numbers provided for Switzerland do not account for the newly commissioned 900 MW Nant de Drance PHES.

[8]The Phelix Day Base is an index computed as the daily arithmetic average of hourly contracts in the bidding zone at that time composed of Germany, Austria and Luxembourg.

driven by the demand and renewable generation in that country. In the winter however, the Swiss electricity prices are driven by the French and Italian loads, and tend to correlate with the French prices. The authors also show that the biggest driver of the Swiss electricity prices is the gas price.

On the impact of gas prices on the volatility of power prices, Rintamäki et al. (2017) tests for the impact of the first difference of natural gas prices, but finds no statistically significant effect, both in Denmark and Germany. As emphasized by the authors, i) the daily changes in natural gas spot prices were small, and therefore unlikely to affect short-term bidding behaviours significantly, while ii) some producers may have been having longer-term gas contracts instead of relying on the spot gas market. We also note that the authors did not test for the impact of absolute gas prices. Yet, it is clear that our findings for the year 2021, where sharp increases are observed in day-ahead price volatility and arbitrage value, are the result of the European gas crisis that led to a substantial increase in gas prices. When open and/or combined cycle gas turbines (OCGT/CCGT) are the marginal generation units, power prices are a multiple of gas prices, which explains that high gas prices induce large swings in hourly power prices throughout the day. In that perspective, it must be noted that the desire of many countries in Europe to reduce their dependence on natural gas imports from Russia may lead to sustained higher natural gas prices and day-ahead power price volatility.

6. Conclusions

This paper investigates the historical value of individual energy storages from DAM arbitrage on the widest geographical and temporal scope studied to date. The study covers every bidding zone in the EU-28 countries, as well as Norway, Switzerland, and Turkey. Historical data used for the valuation start from as far as 2000, for the Netherlands, and span up to 2021. The valuations are made thanks to a dedicated MILP, that the authors run for every bidding zone and every year for which historical realized DAM prices are available. The MILP is designed as a technology-neutral representation of storage, meaning that the conclusions of the paper apply to any storage technology. To enable comparison across different geographies and time periods, the model relies on the classical price-taker and perfect-foresight assumptions. While they bring some limitations, such as overoptimistic valuation results that may not reflect real-world conditions, these assumptions provide a necessary common ground for the analysis. The study's findings are limited to existing energy storage facilities of any size and to additional energy storage facilities that are small enough not to affect market prices.

The results of the valuation analysis reveal significant variations in the value of energy storage from arbitrage, both over time and across different regions. The trend in arbitrage value over the long term has been decreasing, with values before 2010 being several times higher than more recent ones, due to various factors such as the progressive integration of DAM markets (as discussed in Section 2), low fuel prices, and the rise of low-marginal-cost renewable energy sources. Geographically, Norway and Sweden consistently show very low arbitrage values, owing to their high reliance on hydroelectric power, which results in stable DAM prices. Since 2016, Spain and Portugal have also exhibited low storage value from arbitrage. However, the year 2021 saw a remarkable surge in storage value due to the European gas crisis. Overall, these findings emphasize the importance of carefully analyzing the temporal and geographical dynamics of energy storage value from arbitrage, and highlight the need for flexible storage solutions that can adapt to changing market conditions.

Sensitivity analyses were conducted on the full geographical scope to evaluate the impact of round-trip efficiency and storage duration on storage profitability. The results indicate that in markets with low arbitrage value, storage profitability remains low even at very high round-trip efficiencies and storage durations. The potential for energy arbitrage in each country is primarily determined by the dynamics of its DAM, which is the first driver of storage value from arbitrage, followed by round-trip efficiency and storage capacity. In countries with higher arbitrage value, the effect of round-trip efficiency is significant. The marginal value of increased round-trip efficiency is higher in countries with higher arbitrage value. However, the marginal value of storage duration decreases with storage duration and becomes negligible, although always positive, in all studied countries after 4 to 6 hours of storage.

The relationship between annual load factors and arbitrage value was examined, revealing that low arbitrage values are associated with low load factors. In other words, in countries where storage value is low, the spreads in DAM prices are not significant enough to trigger the dispatch of energy storages on a regular basis.

This study examines the impact of variable grid fees on energy storage arbitrage in Belgium from 2016 to 2021. Our results highlight the influence of grid-fee policies on the economic viability of energy storage arbitrage. We found that while grid fees result in a partial transfer of the arbitrage value from the energy storage owner to the TSO, the associated distortion of the DAM price signals significantly reduces energy storage participation in the DAM. For a storage system with 75% round-trip efficiency and 5-hour duration, this leads to load factor reductions of 8 to 27 percentage points over 2016-2020, compared to the scenario without grid fees. Additionally, the non-linear nature of the grid-fee structure favors large charging volumes, which creates an uneven playing field between small and large energy storages. In some cases, this non-linearity even incentivizes loss-making arbitrage operations with the sole purpose of increasing charging volume and shifting to a lower grid tariff. Overall, our findings indicate that the introduction of grid fees up to 2020 reduces the DAM arbitrage value for storage owners by 20% to 50% compared to the scenario without grid fees. Thus, considering these grid fees is essential for any valuation at the base of an investment strategy.

The significant variations in arbitrage value between countries and over time can be attributed to various factors, including the generation mix and its alignment with the load, the presence of energy storage, intermittent renewable generation, and the regulatory framework that surrounds it, cross-border capacities, fuel prices, and more. This paper draws on existing literature to qualitatively examine the impact of these main drivers on arbitrage value, leaving their quantitative evaluation for future research.

In addition to the arbitrage value on DAMs, which is a significant source of value for bulk energy storages, other value streams also exist and are typically considered by storage owners. This paper did not consider the value of capacity remuneration, value from Futures, intra-day, real-time, and reserves markets, nor did it look at the provision of ancillary services, including those related to renewable energy integration. Therefore, while the observed decline in arbitrage value on European DAMs up to 2020 may not accurately reflect the true value of storage historically or in the future, it is essential to put it in perspective with the potential increase in value from other streams, particularly capacity remuneration and all intraday- and reserves-related markets. Storage owners often consider these additional revenue streams to assess the overall value of their investment. Future research could quantify the impact of these alternative value streams and provide a more comprehensive view of the overall value of energy storage.

Finally, the desire of many countries in Europe to reduce their dependence on natural gas imports from Russia may lead to higher natural gas prices, at least in the near term, which in turn might substantially limit or reverse the declining value of storage arbitrage observed over the last decade. However, the overall value of energy storage in different countries going forward, given potentially higher gas prices and greater renewable energy penetration, requires further/different analysis which is outside the scope of this paper.

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