Received: 14 April 2021 | Revised: 14 April 2021 | Accepted: 17 November 2021

DOI: 10.1002/wene.431

ADVANCED REVIEW

WIREs ENERGY AND ENVIRONMENT WILEY

On the economics of storage for electricity: Current state and future market design prospects

Reinhard Haas[1] | **Claudia Kemfert**[2] | **Hans Auer**[1] | **Amela Ajanovic**[1] | **Marlene Sayer**[1] | **Albert Hiesl**[1]

[1]Energy Economics Group, Vienna University Technology, Vienna, Austria

[2]Energy, Transportation, Environment Department, Deutsches Institut fur Wirtschaftsforschung eV, Berlin, Germany

Correspondence
Reinhard Haas, Energy Economics Group, Vienna University Technology, Gusshausstr 25-29, Vienna 1040, Austria.
Email: haas@eeg.tuwien.ac.at

Edited by: Peter Lund, Co-Editor-in-Chief and John Byrne, Co-Editor-in-Chief

Abstract

Since the early beginnings of the electricity system, storage has been of high relevance for balancing supply and demand. Through expanded electricity production by variable renewable technologies such as wind and photovoltaics, the discussion about new options for storage technologies is emerging. In addition, the electricity markets were subject to remarkable alterations. Some developments which describe these changes are increasing electricity generation from variable renewables and the continuing decentralization. These developments have led, among other required transformations, to demands for additional capacities of storage technologies. However, their economics will play a crucial role in their effective market penetration in the following years. The core objective of this work is to conduct a review on the relevance of storage options for electricity and its costs, economics, welfare effects, and on issues of electricity market design. In addition, based on expected Technological Learning prospects for future economics are derived. The major result is that the perspectives of electricity storage systems from an economic viewpoint are highly dependent on the storage's operation time, the nature of the overall system, availability of other flexibility options, and sector coupling. All market-based storage technologies have to prove their performance in the large electricity markets or if applied decentralized, the (battery) systems compete with the electricity prices at the final customers level when the battery costs are also taken into consideration. Yet, new storage capacities should only be added when it is clear that electricity generation from variable renewables will also be expanded in a way that excess generation is expected.

This article is categorized under:

Policy and Economics > Green Economics and Financing
Energy and Power Systems > Energy Infrastructure
Emerging Technologies > Energy Storage

KEYWORDS

arbitrage, battery storage, economics, pumped hydro storage, social welfare

1 | INTRODUCTION

In the last few decades, electricity markets virtually worldwide were subject to significant alterations. In the European countries, these trends happened due to the targets set, the directives launched, and the policies introduced by the European Commission. These were, for example, the Internal Electricity Market Directive, the Renewable Energy Directive, and the Clean Energy package (see IEC, 2019; Jülch, 2016; Sterner & Stadler, 2019). As the amount of electricity generated by variable renewable energy technologies (VARET), mainly wind and photovoltaics (PV) increases, electricity storage technologies and their relevance for the wholesale electricity markets becomes more vital.

The European Commission (EC as well-known) has implemented goals for raising the amounts of electricity produced from renewables. Indeed, the electricity generation from intermittent renewables like wind and PV has risen dramatically in recent years (see Figure 1). The graph depicts how between about 1990 and 2019, in the European Union (EU-28), VARET (without hydro) increased from below 20 TWh to 500 TWh, the largest amounts from wind power plants and solar PV systems. Energy storage may be a critical component to even out demand and supply by proper integration of VARET into the electricity system. Storage could play an important part when transforming our whole energy system into a more environmentally benign and finally fully sustainable one. Necessary aspects are enhancing supply security, the flexibility across the entire system, the reliability of the European electricity and ultimately, the whole energy supply. Given the ambitious goals for renewable electricity generation of the EU as well as implementation, the possible role of electricity storage in the overall energy system of the future is crucial. In Germany in particular, the future need for storing electricity has been the subject of intense discussion in the context of the ambitious renewable energy targets set as a part of the energy transition. A comprehensive study by Schill et al. (2015) concludes that in the short and medium-term, no significant extension of storage for electricity is required, given that other flexibility measures are used. In the long term, higher amounts of VARET, as well as bigger capacities of storage will be

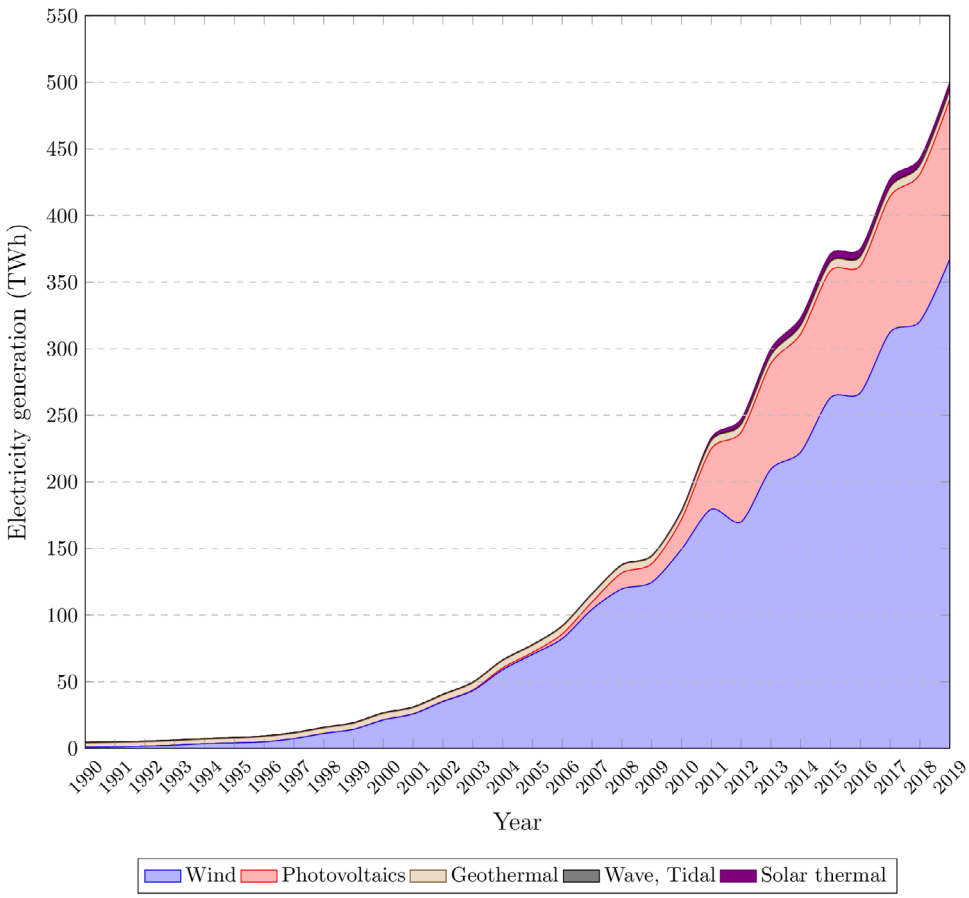

FIGURE 1 Development of electricity from variable renewable energy technologies (excluding hydro) in EU-28 between 1990–2019, in TWh (Eurostat, 2014, Eurostat, 2021, own estimations)

needed. The EU already pointed toward this technology in 2011 and issued a related report on storage, respectively (European Commission, 2011).

Since there are many storage solutions available (see, e.g., Sterner & Stadler, 2019), the first economic question is merely comparing the future overall costs of various types of storage (to find the ones with best economic performance, accounting for every applicable cost category and corresponding conversion figures such as efficiency, see e.g., investigations by Jülch, 2016; Schmidt et al., 2019).

Regarding the role of storage capacities in an electricity system, there are various views from different stakeholders' point-of-view:

- From a storage-owning company's viewpoint, the possibility of obtaining an arbitrage determines the economic value of a specific additional storage unit. Under these conditions, the enterprise buys electricity at the market when it is a good bargain and sells the stored electricity when the market price is sufficiently above. Straightforward, the major criteria for a positive economic performance is provided by the well-known term of the price spread (see e.g., Ajanovic et al., 2020; Ehlers, 2011; Sioshansi, 2010).
- In addition to the arbitrage approach mentioned above, there is also the possibility of own use of self-generated and then stored electricity "behind the meter" (see EEEP symposium on prosumage Hirschhausen, 2017; Schill et al., 2017), for example, in a household, at a farm, in a supermarket or in an office building. In this context, storage costs compete with the price of electricity for end consumers, and if they are less than the final electricity prices (with all fees and taxes considered but not including the fixed costs), then the costs of storage demonstrate a positive economic performance.

As benefits of additional storage capacity on a household level (prosumage), increasing system flexibility (e.g., previously unused demand-side management of households), options for sector coupling (e.g., car battery charging) as well as a reduction of PV feed-in peaks and thus a possible defer of expensive distribution grid expansions are discussed. Moreover, there is the opportunity for higher energy efficiency and awareness in the case the electricity is generated and stored by the individual owners, depending on the rebound effect (see Schill et al., 2017).

- Storage is one way to even out differences between electricity supply and demand profiles and strike a corresponding balance. Yet, here we have to mention in an essential way that the major task of bringing about a proper balance between generation and consumption has existed in the electricity markets and system since its inception. Due to the apparent disparity between supply and demand profiles, also nuclear power systems, for example, require storage. Since with VARET balancing requirements are present also over longer time periods such as months or years, the requirements for corresponding electricity storage capacities for these periods have to be considered in system planning, too (see Ajanovic & Haas, 2019).
- At present, there is a particular focus on incorporating larger quantities of electricity produced by VARET in the electricity markets. Zerrahn et al. (2018) investigate the economic performance of storage for electricity from VARET and show that the needs for storage decrease substantially if the shedding of peaks from VARET is allowed. They come to the conclusion that the necessity for electrical storage is unlikely to hinder the transformation toward VARET. In a more detailed analysis, with an open-source model Schill and Zerrahn (2018) show that up to about 80% of VARET integration in the electricity system, the need for additional storage capacity remains moderate when alternative flexibility options are used. However, with increasing electricity production from VARET and the need for their integration, the demand for additional capacities of storage will increase substantially.
- In addition, there are more possibilities for storage in smart and sustainable energy systems in the future than in the traditional system of the past (see Ajanovic et al., 2020; Lund et al., 2016).
- A fundamental point of discussion of economists is the issue of the electricity market design and how to cope with market power. Whether storage operators may exert market power is discussed (e.g., Schill & Kemfert, 2011; Sioshansi et al., 2009).
- From society's point of view, the economics of social welfare is a very important issue of interest. Sioshansi et al. (2009) and Sioshansi (2010) analyze the relations between economics and welfare effects. They pretend that the storage system is owned by only one merchant storage operator in Sioshansi et al. (2009). Their major result is that for the owner of the storage usually, no suitable proper incentives exist to operate the storage in a procedure that optimizes social welfare.

- Moreover, we highlight that in addition to storage, there are also other flexibility measures possible in the electricity system. It competes with alternatives such as load shifting, smart grids... (see e.g., Ajanovic et al., 2020). As a consequence, in order to make a long-term economic decision, all potential storage solutions must be considered at the same time. An extensive literature review and analysis on the mentioned interactions between storage and other flexibility options has been conducted by Prol and Schill (2020).

The core objective of this work is to investigate the economics and the future perspectives of various opportunities for storing electric energy as there are batteries, central and decentral pumped hydro storage systems with daily or monthly capacity, and also chemical ones such as hydrogen and methane derived by power-(electricity)-to-gas (PtG) technologies. While for the longest period, pumped hydro storage has been the prevailing technology, in recent years also other types of storage emerged. The focus is especially on the interaction of storage and VARET, on welfare effects of storage and on issues of electricity market design in an energy economic view. It is important to note that we do not deal with grid issues in this paper. In addition, based on expected Technological Learning prospects for future economics are derived. This work builds on and extends the work presented in Ajanovic et al. (2020) and Hiesl et al. (2020).

The paper is organized as follows: Section 2 provides background information about the different electricity storage options. Section 3 documents selected references. In Section 4, the economics and costs of three technologies—pumped hydro storage and hydrogen as market-based systems, as well as batteries as an example for own use—are analyzed. The value of storage for the electricity system and the society is documented in Sections 5 and 6, respectively. Section 7 discusses aspects of renewable production peaks and the need for additional capacities of storage and Section 8 shows future scenarios based on technological learning. Major conclusions are presented in Section 9.

2 | BACKGROUND

For as long as electricity systems have existed, pumped hydro storage has been the most important tool for managing supply and demand. They accounted for roughly 97% of all electricity storage in the EU in 2019 (see Erbach, 2019). Despite being a 10-year-old reference, Deane et al. (2010) is significant since it is the clearest review of pumped hydro plants throughout the field. A more recent study focusing on batteries is Fu et al. (2018).

We can divide the different storage options into mechanical-, electrochemical-, chemical-, and electrical storage. Figure 2 provides an overview of storage technologies. A comprehensive survey on storage technologies and a classification of their applications is provided in Table 1. Aside from pumped hydro storage, batteries are the most mature storage technology (see e.g., Behabtu et al., 2020; Ferreira et al., 2013). Ninety percent of the total installed battery capacity for large-scale storage are Li-ion batteries (IRENA, 2019). Table 2 gives an overview of installed capacity for various storage technologies around the world according to the DOE, 2020 database.

In this work, we focus on long-term storage technologies—pumped hydro storage, compressed air energy storage (CAES), as well as PtG hydrogen and methane as chemical storage—and batteries. We analyze the systemic, energetic,

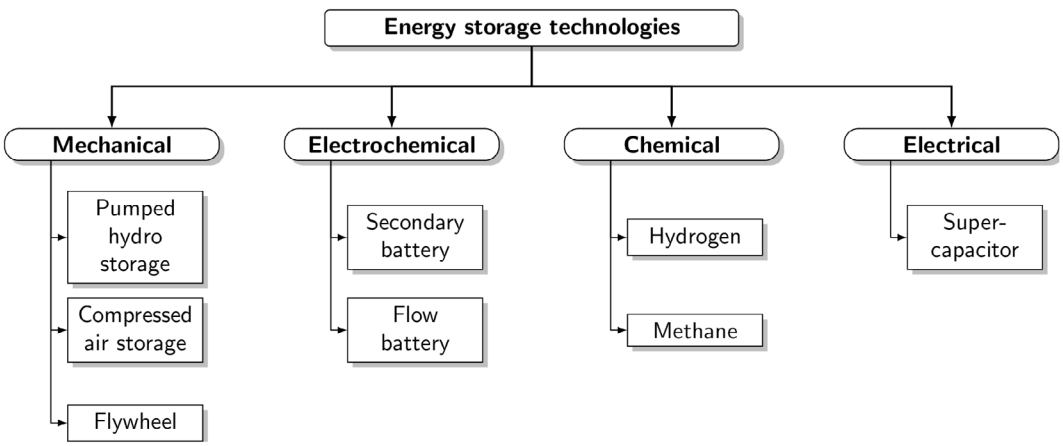

FIGURE 2 Classification of electricity energy storage systems based on the form of energy stored, adapted from (Rahman et al., 2020)

TABLE 1 Specifications for different storage options (Ajanovic et al., 2020; Bünger et al., 2016; EASE, 2021; Eckhouse & Stringer, 2021; Fuchs et al., 2012; Zablocki, 2019)

Type of storage	Power range	Response time	Efficiency (%)	Energy density (Wh/l)
Mechanical				
Pumped hydro	10 MW–3 GW	sec–min	70–85	0.2–2
Compressed air	100 MW–1GW	sec–min	40–75	2–6
Flywheel	100 kW–20 MW	10–20 ms	70–95	20–80
Electrochemical				
Li-ion battery	1 kW–300 MW	10–20 ms	85–98	200–400
Lead-acid battery	Some kW–100 MW	<sec	75–90	50–80
Flow battery	Several kW–100 MW	10–20 ms	60–85	20–70
Chemical				
Hydrogen	1 kW–1 GW	sec–min	25–45	600
Methane	1 MW–1 GW	sec–min	25–50	1800

TABLE 2 Installed capacity and amount of different storage systems worldwide (DOE, 2020)

Type of storage	Operational	Contracted	Under construction
	GW (storage system)	GW (storage system)	GW (storage system)
Mechanical storage	169.45 (380)	2.29 (10)	0.07 (4)
Electrochemical storage	1.79 (768)	0.54 (63)	0.35 (7)
Chemical storage	0.02 (9)		

and economic perspectives and compare the costs of different storage types depending on the expected full-load hours, the efficiency of the storage and the costs of electricity used. Thermal storage is not considered because it is in practice not common to transform back low-temperature heat into electricity.

Basically, many options for storage categorization exist (depending on the practical types of the storage, e.g., batteries, pumped hydro storage, chemical products) in the electricity system of the future. Pumped hydro storage is the by far most widely deployed traditional solution at the transmission grid level, pumping during periods of excess generation and turbining during times of scarcity. Furthermore, electricity may be stored in chemical storage by using PtG technologies to produce hydrogen, methane, or other chemical products. Grid-level large-scale battery demonstration projects were recently implemented in China, Europe, and the United States, mainly for reducing peaks in the electricity network and for improving the security of the electricity supply. The latter supported 16 grid-level battery projects with $185 million (Fan et al., 2020). Eventually, at the level of earlier called consumers—today named prosumagers (Schill et al., 2017)—there are the options of storage in the battery of a BEV or a stationary chemical battery "behind the meter."

3 | SELECTED REFERENCES

Especially in the last few years, the literature has increasingly dealt with electricity storage, with Amirante et al. (2017) and Rahman et al. (2020) giving a systematic overview of technical details of different storage technologies. In this Section, we will first discuss papers dealing with electricity sector modeling with high shares of VARET that discuss the storage needs and capacity planning models. As storage is not the only flexibility option in an electricity system with high shares of VARET, we further show alternatives. Despite those options being available, storage technologies will still play a major role in the future electricity system, hence in Section 3.3 significant papers on the current and future economics of storage based on technology cost are discussed.

3.1 | The role of storage in electricity systems with high shares of renewables

A strain of literature deals with electricity sector modeling, including storage with different geographical coverage, time horizons, and methodological approaches (Prol & Schill, 2020). Those models can further be classified according to Prol and Schill (2020), who provide an extensive literature review on all of them, into price-taking arbitrage models with historic electricity market prices, models based on time series of VARET as well as the state-of-the-art electricity sector models, often including capacity expansion.

The first analysis covering Germany has been Schill (2014), followed by Zerrahn and Schill (2017), who give an extensive review on electricity storage models. Using the open source-model DIETER they show that up to the integration of about 80% VARET into the power system, the need for additional storage capacity remains moderate if alternative flexibility options are used. Those results are presented in Schill and Zerrahn (2018). The goal of the model is to show the cost-minimizing combination of generation, demand-side management, and electricity storage (including battery, pumped hydro storage, and PtG) and shows that the need for storage triples when all electricity production comes from VARET. However, hardly a long-term storage is needed, assuming other measures are available, importantly electricity production from biomass. Regarding this aspect, the study is at the lower end of the spectrum of the literature review in Zerrahn and Schill (2017). Zach and Auer (2016) investigate the relevance of bulk storage systems in a high-RES-share—a scenario for the years 2030 and 2050 in Europe, by regions. They find that new power plants are required by 2030 in several of the investigated regions, whereas some countries are already able to meet residual load by enough flexible generation options in the long run. Additionally, they find that especially the Iberian Peninsula will have a great overproduction of electricity by VARET for which bulk electricity storage or exports will be needed.

Furthermore, it is vital to evaluate the whole system context to identify the needed storage capacity of an electricity system, which is another important strain of literature. An extensive analysis of all economic aspects of storage technologies, including the existing market framework based on Central Europe, is given by Gatzen (2008). This aspect is also included in the stochastic model of Powell et al. (2012) where different storage solutions were discussed. They find that using approximate dynamic programming, storing energy is ideal, whereas not in a scenario-based approach, especially not with optimal foresight within the scenarios.

Steffen and Weber (2013) apply peak-load pricing theory and further develop a model to identify the effective amount of storage in an energy system with high shares of VARET, also including thermal capacities. Their main conclusion is also in line with previously analyzed papers, saying that increasing the amount of VARET (considering between 40% and 60% VARET) does not automatically require a larger amount of storage. Applying those analytical models in an applied scenario with even higher shares of VARET (up to 80%) Böcker et al. (2015) find that PV combined with storage will be essential for a well-functioning energy portfolio in the year 2040. A sensitivity analysis indicates that the storage amount is highly dependent on the investment costs and political targets. Steffen and Weber (2016) focus on pumped hydro storage, applying optimal control theory, a continuous, deterministic price curve as well as conducting a case study on the economics of pumped hydro storage in Germany. Their main finding is that the possible arbitrage profit decreased in the analyzed time between 2008 and 2011 due to fewer fluctuations in electricity prices. Zöphel and Most (2017) also model interesting scenarios of different renewable energy shares, CO_2 price and storage types and show that higher shares of electricity from VARET and a higher CO_2 price result in higher marginal values for storage. The hourly and daily storage types are more sensitive to higher CO_2 prices due to lower investment costs.

Geske and Green (2020) analyze the optimal storage design from an economic standpoint. They show how electricity storage is operated optimally when the load net of VARET output is uncertain. Effective storage operation and welfare effects, including the model of Crampes and Moreaux (2010), will be further discussed in Section 6.

3.2 | Other flexibility measures

A clear conclusion from all analyzed studies under Section 3.1 is that storage will be needed to a certain extent in the electricity system of the future. Thus, it is clear that storage will not be the only solution to bring demand and generation closer together. A variety of other flexibility measures exist, which are discussed most thoroughly in Lund et al. (2015). The paper discusses energy storage, demand-side management, grid ancillary services, supply-side flexibility, advanced technologies, infrastructure, and electricity markets. The main conclusion of the analysis is that there is a large number of options for flexibility from which many are already built-in the current system. Electricity demand has

been changing; thus, such measures were necessary already early on. Additional flexibility demand can easily be treated with added storage units in the long run. Bloess et al. (2018) explicitly research the topic of interlinking the power sector with the heat demand on a residential basis and conclude that heat pumps and passive thermal storage are particularly favorable options. Also, on an industrial level, this linkage is favorable as it is possible to electrify 78% of the industrial energy demand (Madeddu et al., 2020).

Another measure under supply-side flexibility that is being widely discussed, especially in Germany, is the curtailment of VARET when there is a mismatch between production and demand. In response to Sinn (2017), who stated that the further expansion of wind and solar energy in Germany would reach a limit due to lack of available electricity storage, Zerrahn et al. (2018) find the demand for storage is lower than predicted in the literature. In the above-mentioned analysis by Sinn only marginal solutions are addressed, hence either no electricity storage or no renewable energy curtailment. However, a combination of storage and curtailment is economically more plausible (Schill et al., 2018). Zerrahn et al. (2018) show that the further expansion of VARET will not lead to an excessive need for additional storage and straightforward, the available capacity of electricity storage will not be the bottleneck for the energy turnaround. The storage requirement can be significantly reduced, in particular by a moderate temporary adjustment of the generation peaks of wind as well as PV power plants. Moreover, in the context of a future intensified sector coupling, new flexible consumers in combination with other downstream energy storage forms can further reduce the need for electricity storage.

The latest research of optimal investments in flexibility options, based on the REFLEX project, is from Möst et al. (2021). With the electricity market model ELTRAMOD, different scenarios differing in the respective VARET amounts, are analyzed regarding sector coupling and flexibility options. They conclude that cross-sectoral influences are essential for identifying the right investment and dispatch solutions. As a result, applying for example, demand-side management reduces the possible storage profit hence supporting that flexibility options are generally in competition with each other. The exceptions and more details are discussed in Section 7.

3.3 | Economics of electricity storage

Another major aspect of electricity storage is the respective storage costs based on technology cost calculations. The main method used to assess the costs of different storage technologies is the levelized cost of energy (LCOE) method. One study dealing with LCOE is Pawel (2014), dealing with a PV and storage combined power plant and concluding that the C rate has a stronger influence on the cost than the round-trip efficiency of the storage technology. On a utility-scale, Zakeri and Syri (2015) analyze pumped hydro storage, CAES, flywheel, batteries, superconducting magnetic energy storage, supercapacitors, and hydrogen energy storage and find substantial differences among the technologies.

In a scenario in Germany with congested transmission grids, Härtel et al. (2016) introduce storage technologies to reduce curtailment and they find that only recovering the 2016 and 2025 curtailed energy amounts does not cover the costs of any storage technology based on LCOE calculations. Jülch (2016) uses this method to conduct an economic comparison of various storage technologies. They come to the finding that battery storage systems are still more expensive than others at the point-of-time of their investigation (2016 published). Yet, they are expected to bring about a significant drop in investment costs in the next years. PtG and adiabatic CAES systems could also become cost-effective. In a sensitivity analysis, they find that for most storage technologies, the quantity of energy discharged and the cost of electricity purchased are the most important parameters. In a more recent work, Mostafa et al. (2020) analyze costs of long-term high, medium-term, and short-term energy storage technologies and expand their research to different power and energy ratings. They find that pumped hydro storage is the most competitive among long-term, sodium-sulfur batteries among medium-term and supercapacitors among short-term storage technologies. Topalović et al. (2022) apply the LCOE approach for the Western Balkans, assessing pumped hydro storage and battery storage technologies and finding that pumped hydro storage is still the most economical storage technology in this region.

Also, an outlook on the future is important when discussing electricity storage costs, which several studies do consider.

The economic potential of power-to-gas storage, in the long run, is investigated by Baumann et al. (2013). They argue that PtG is one of the most important long-term options for storing electricity. Operators may use the PtG systems for purchasing electricity and selling natural gas. However, investigations of the best storage dispatch strategies result in the finding that the obtained contribution margins (CMs) reached today and until 2032 will not be enough

reimbursement for VARET and fixed costs. Economic viability cannot even be reached by trying to deal with negative tertiary reserve. Considering, in addition, looming new competing technologies, they state that in the next years, PtG-systems cannot make profits. However, they may become a relevant technology when heading for sustainable energy systems in the long run. In more recent studies, Schmidt et al. (2017), Ajanovic and Haas (2019) as well as Böhm et al. (2020) discuss the actual costs and future perspectives of producing hydrogen from VARET.

Kittner et al. (2020) apply the technological learning approach for grid-scale energy storage to discuss future costs. A new approach to discuss future electricity storage cost is introduced by McPherson et al. (2018), using the integrated assessment mode MESSAGE to include the uncertainties of VARET provision and abatement cost. They conclude that the overall storage provision will largely depend on the costs and find that PtG has a good potential for decarbonization of many sectors.

When discussing PtG options, it is also important to regard the corresponding CO_2 emissions hence the climate impact. Several different production processes of hydrogen are available. Dawood et al. (2020) provide an extensive literature review, clustering the production methods according to the feedstock used for production. Solely hydrogen produced by renewable electricity, such as wind and PV has a positive ecological performance and is often characterized as green hydrogen (Parra et al., 2017). However, the technical potential of overall VARET generation is limited; hence there is the argument that it is also limiting the hydrogen production potential of green hydrogen. Kakoulaki et al. (2021) calculate an electricity generation potential of 10 000 TWh/year in the EU for wind, solar PV, and hydropower electricity, with a production of around 819 TWh in 2019. Therefore, according to the authors, there should be enough renewable resources to meet the hydrogen demand in the EU. Those findings are further displayed for 109 regions in the EU27 and United Kingdom, showing that the highest production potential will be in Spain. This is also in line with the findings of Zach and Auer (2016). Another emphasis to solely rely on hydrogen produced by renewable resources has been recently published by Howarth and Jacobson (2021). They find that when using blue hydrogen, which is hydrogen produced by natural gas with the carbon captured and stored, it emits only 18%–25% less greenhouse gas emissions than gray hydrogen (by steam reforming of natural gas) and still has 20% higher emissions than using natural gas or coal for heat. This is mainly due to the fugitive methane emissions that arise when powering the carbon capture. Another related work is by Mehrjerdi (2019). It studies what the optimal solution of both fossil combined with VARET, PtG generation for hydrogen respectively methane production is. Their designed PtG process effectively includes an intermittent solar system reducing overall CO_2 emissions, maximizes profits, and minimizes the running costs simultaneously.

PtG systems are not able to compete with normal natural gas power plants if they only deliver hydrogen and substitute natural gas by SNG, which is the result of an investigation done via a combined techno-economic analysis and a corresponding environmental LCA of PtG-plants by Parra et al. (2017). Given also the higher costs of all hydrogen options, if considering the change to a hydrogen-based storage system, only green hydrogen should be used to offset the higher costs with lower emissions.

Regarding battery storage systems, a highly discussed topic is the availability and use of rare raw materials. According to Greim et al. (2020) one of them, namely, lithium is crucial for the success of the transformation of our energy system. They urge to recycle and research in cutting the lithium intensity of batteries in the transportation sector. Duffner et al. (2021) provide an extensive overview of this research on post-lithium-ion and lithium technologies such as solid-state lithium metal, lithium-sulfur and lithium-air batteries and sodium-ion batteries, considering all production stages and manufacturing compatibility with the existing production infrastructure.

In this work for modeling the wholesale electricity market, we choose a fundamental approach, in which the intersection of generation merit order and the curve for demand at any hour yields the related price in the wholesale electricity market wholesale. It is essential to mention that the amount of storage installed has an effect on the market price for storage charging and discharging and on the price spread.

4 | THE COSTS OF STORING ELECTRICITY

Our methodology builds on the investigation of total costs of various options for storing electrical energy (see Haas & Ajanovic, 2013). Equation 1 describes how the costs of storing one kWh of electricity C_{STO} are calculated. The price spread in the wholesale market for energy and the total full-load hours decide whether market-oriented storage is economically viable. The importance of the full-load hours per year for the economic performance of storage systems was discussed (e.g., in Ajanovic & Haas, 2014) and this is the basics of analyses on the market perspectives of centralized storage systems.

The costs of storing a kWh of electricity C_{STO} e.g. by a pumped hydro storage plant, are calculated as

$$C_{STO} = \frac{\frac{IC \cdot CRF + C_{OM}}{T} + C_E}{\eta_{STO}} (€/kWh) \tag{1}$$

with:

IC: investment costs of storage (€)
CRF: capital recovery factor (1/year)
C_{OM}: operation and maintenance costs of the storage (€/year)
T: full-load hours (hours per year)
C_E: costs of electricity (€/kWh)
η_{STO}: storage efficiency

Equation 2 indicates how a capital recovery factor is calculated. It is determined using the depreciation period and the interest rate applied (we use 5%)

$$CRF = \frac{z(1+z)^n}{(1+z)^n - 1} (1/year) \tag{2}$$

with:

z: interest rate (%)
n: depreciation time (years)

Figure 3 depicts the overall costs of storing electricity in new plants or devices for various storage systems for the year 2018, including costs for capital, electricity, and operating and maintenance (O&M). As observed, a huge range exists for the spread of the overall costs—from about 8 cents/kWh up to close to 1 EUR/kWh. Furthermore, rather different percentages of the single cost components are seen. Even for batteries alone, the range is between 0.2 cents/kWh

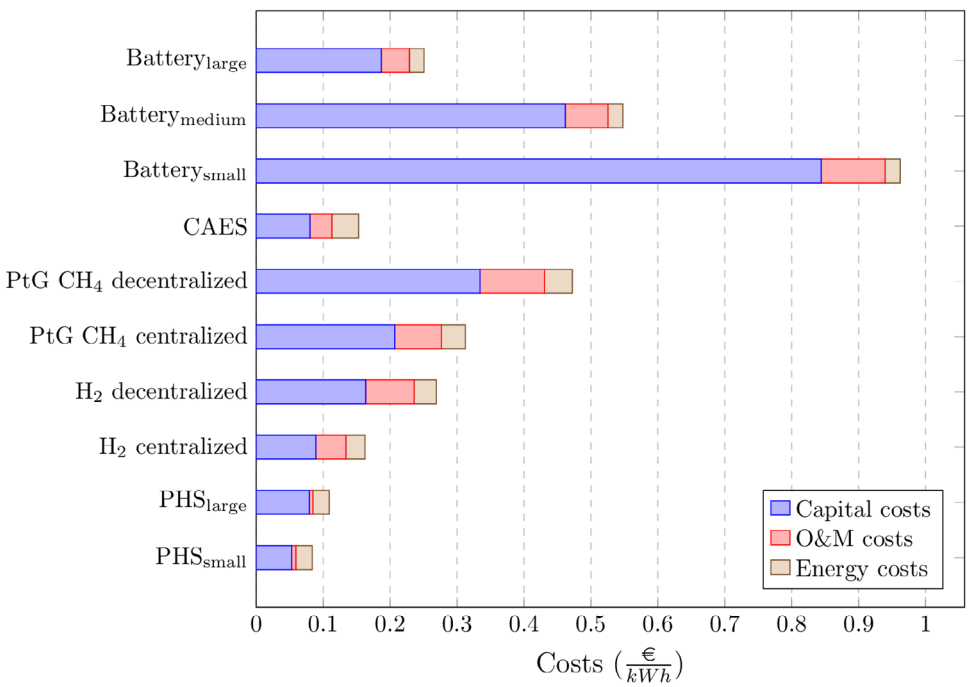

FIGURE 3 Storage costs in total for electricity using various technologies (including costs for capital, energy as well as operation & maintenance (O&M) in 2018

and almost 1 EUR/kWh. For example, looking at annual 500 full-load hours, the magnitude of capital costs is a factor of four higher compared to 2000 h/year, see Figure 4

Table 3 gives an overview of the different assumptions made concerning technical parameters applied in this study and Table 4 shows the specific numbers used for the economic calculations.

The major notable findings of this research are: The significant basic barrier for the economic performance of storage is their low utilization rates (full-load hours), as shown in Figure 4. Approximately 2000 full-load hours should be seen as a minimum value for running storage systems profitably.

A second explanation for long-term storage facilities' limited attractiveness is that they have to compete with demand-side options, such as demand response, demand-side management, and demand-side control, as well as with network expansion opportunities, see more details in Section 7. Furthermore, decentral storage might be an additional option. The investment costs of the latter are not expected to decrease much more rapidly. However, the price plateau of the "prosumager" on which they will compete is (and will stay) on a substantially higher level.

Another explanation why the economics of long-term storage systems in the wholesale markets are moderate is their self-cannibalism. That is to say, each new storage unit added has fewer full-load hours than the previous one, hence decreasing the price spread and, as a result, its own economic efficiency (Ehlers, 2011). All those aspects will be discussed later in more detail.

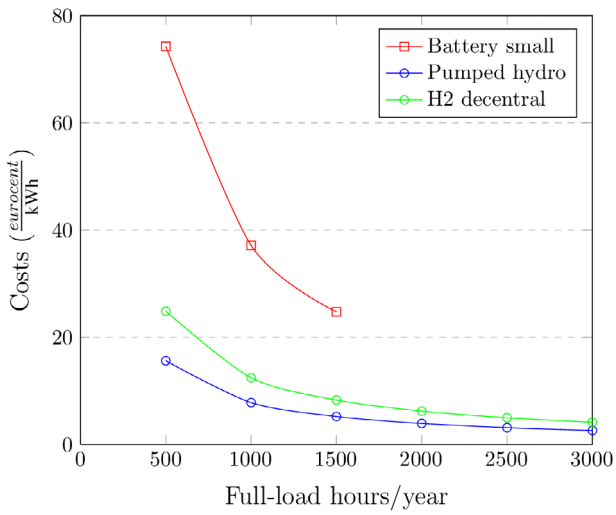

FIGURE 4 Storage costs for electricity in total applied to the three major technologies of this investigation related to the number of annual full-load hours

TABLE 3 Summary of the technical parameters used in this research (own investigations for the year 2018 for efficiencies)

Type of storage	Capacity (MW)	(kWh)	Efficiency	Full-load hours (h/year)
PHS_{small}	200		0.82	1800
PHS_{large}	350		0.82	1800
H_2 centralized	10		0.7	1800
H_2 decentralized	0.5		0.6	1800
PtG CH_4 centralized	10		0.56	1800
PtG CH_4 decentralized	0.5		0.48	1800
CAES	350		0.5	1800
$Battery_{small}$	0.0025	5	0.88	500
$Battery_{medium}$	0.015	30	0.9	700
$Battery_{large}$	0.5	1000	0.92	900

TABLE 4 Overview of the parameters used in economic investigations (all figures are of 2018, Source: own research and Ajanovic & Haas, 2019)

Type of storage	Investment costs (€/kW)	Investment costs (€/kWh)	O&M costs (€/kW year)	Depreciation Time (years)
PHS_{small}	1200		5	30
PHS_{large}	1800		5	30
H_2 centralized	1400		25	20
H_2 decentralized	2200		35	20
PtG CH_4 centralized	2600		35	20
PtG CH_4 decentralized	3600		40	20
CAES	900		25	20
$Battery_{small}$	(2400)[a]	1200	20	8
$Battery_{medium}$	(1880)[a]	940	15	8
$Battery_{large}$	(1000)[a]	500	10	8

[a]Using 0.5 kW/kWh calculated depending on the numbers for (€/kWh storage capacity).

5 | THE VALUE OF STORAGE FOR THE ELECTRICITY SYSTEM

In the first and second chapter, the types of technologies analyzed in this work have been described. In this chapter, emphasis is put on the economics of the currently three most important technologies: pumped hydro storage and hydrogen, as examples for storage systems deployed in competitive markets, and decentralized batteries implemented by end-users, so-called "prosumagers."

As previously stated, maximizing the overall profit made is the goal of a storage operator competing in a market. This profit is defined as revenues R minus costs C. In the further calculations, we only focus on the arbitrage value. Nevertheless, storage can also ensure capacity adequacy, provide control reserves and other ancillary services and manage network congestion (Schill et al., 2015). Equation (3) is the basic approach for the calculations of market-based storage:

$$\max \Pi_t = \sum R_t - C_t = \sum \left(P_{H_t} - C_{gf_t}\right) \cdot D_t - \left(P_{L_t} + C_{gf_t}\right) \cdot \frac{D_t}{\eta_t} - \mathrm{IC}_0 \cdot \mathrm{CRF} - C_{OM_t} \tag{3}$$

with:

C_{OM}: costs of operation and maintenance of the storage (€/year)
C_{gf}: costs of grid fee
CRF: capital recovery factor (1/year)
D_t: demand of energy (kWh)
IC: investment costs of storage (€)
P_H: selling (high) price of electricity on the market (€/kWh)
P_L: purchasing (low) price of electricity on the market (€/kWh)
Π: profit (€)
η: storage efficiency

From the perspective of a decentralized storage operator, the aim is still to optimize profit, but it will be calculated differently now: The profit is obtained from subtracting the costs C_t from the savings S_t The corresponding equation is:

$$\max \Pi_t = S_t - C_t = D_{\mathrm{own}_{\mathrm{use}_t}} \cdot P_{\mathrm{final}_t} - \mathrm{IC}_o \cdot \alpha - C_{OM_t} \tag{4}$$

with:

$D_{\mathrm{own}_{\mathrm{use}}}$ own consumption of storage delivered (kWh)
P_{final} final customers price of electricity (except fixed costs) (€/kWh)

As shown already above in Equation (1), the expenses for energy pose a significant impact factor for obtaining the overall cost of storage. For further analysis, we used the classified frequency of the average electricity costs as well as the corresponding revenues for the example of EXAA (wholesale exchange in AT) for the year 2020, considering storage losses for the pumped hydro storage plant.

5.1 | Pumped hydro storage

The most widely deployed type of storage for electrical energy is pumped hydro storage. Their costs, revenues, and profits, related to full-load hours per year are illustrated in Figure 5, taking into account also the losses of the pumped hydro storage. Figure 5 depicts the expected overall profit for a level of 2000 annual full-load hours (green plus yellow rectangle in Figure 5). When adding a grid fee of 1.5 cents/kWh, the total profit for 2000 full-load hours per annum is more than halved (only green rectangle in Figure 5). This also applies to the other storage technologies, taking the different efficiency (storage losses) into account.

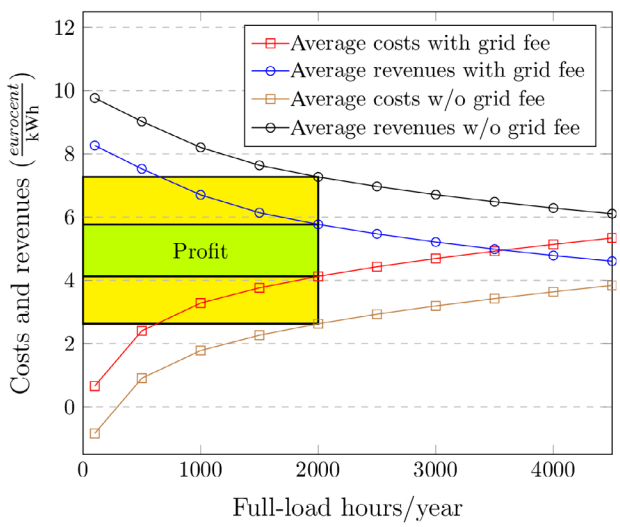

FIGURE 5 Profits, costs and revenues of existing pumped hydro storage depending on full-load hours per year, including (green rectangle) and excluding fee for grid use (green and yellow rectangle)

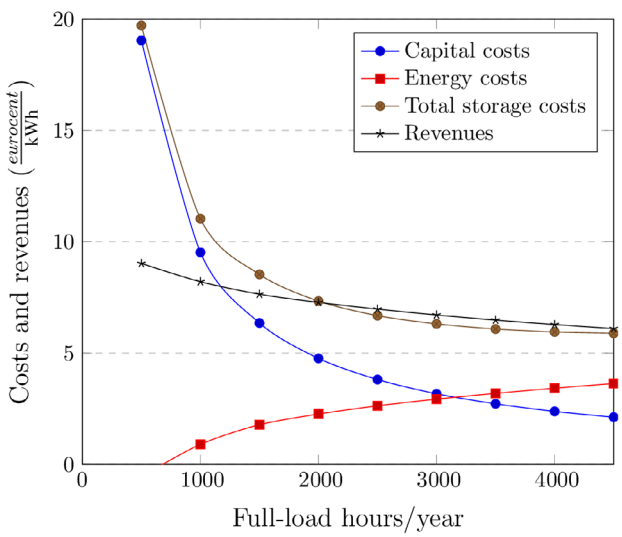

FIGURE 6 Total storage costs & revenues of pumped hydro storage system new constructions based on full-load hours

Figure 6 depicts the overall costs and revenues of pumped hydro storage systems, excluding a fee for grid use based on the full-load hours per year. The key insight from this figure is that, in the absence of a grid fee, pumped hydro storage could be cost-effective between about 2500 and 4500 full-load hours per year. As seen from Figure 6, the overall costs (capital, energy, and cost of O&M) are at about the same range as the revenues obtained by selling electricity from pumped hydro storage

In addition to the previously outlined arbitrage profits of pumped hydro storage, it is worth noting that pumped hydro storage is also well suited for frequency regulation, particularly automatically and manually activated Frequency Restoration reserve, where high revenues could be generated through the provision of reserve capacity and the activation price when they are required (Dallinger et al., 2019). Summing up: in total, pumped hydro storage can be deployed best for energy management/shifts of peak production through price spreads, redispatch, and frequency control.

In Figure 7, it is shown how the price of pumped hydro storage based on the merit order curve is set. Since pumped hydro storage, unlike thermal power plants have very low short-term marginal costs, they are determined by shadow prices to represent storage scarcity (due to low marginal costs, otherwise it would lead to storage depletion in the first hour of operation). These shadow prices are based on the combined cycle power plant's marginal costs and thus determine the competitiveness of the storage facility under normal operating conditions (Havranek, 2012).

In a second use case with a high share of electricity imports from VARET, we show in Figure 8 the merit order curve under "normal dispatch." In the case of grid congestion, however, redispatch measures are necessary to leave the situation on the grid. In case pumped hydro storage capacities are available (contracted by the transmission system operator), they are active and "compensate" for some of the electricity imports. The price for pumped hydro storage is therefore on the same level as the substituted imports. However, redispatch is called by the transmission system operator; hence the costs are paid from the grid tariffs and wholesale prices are not affected by grid congestion. Additionally, the profit of pumped hydro storage operators is above the merit order price, as they are paid for the redispatch reserve capacity.

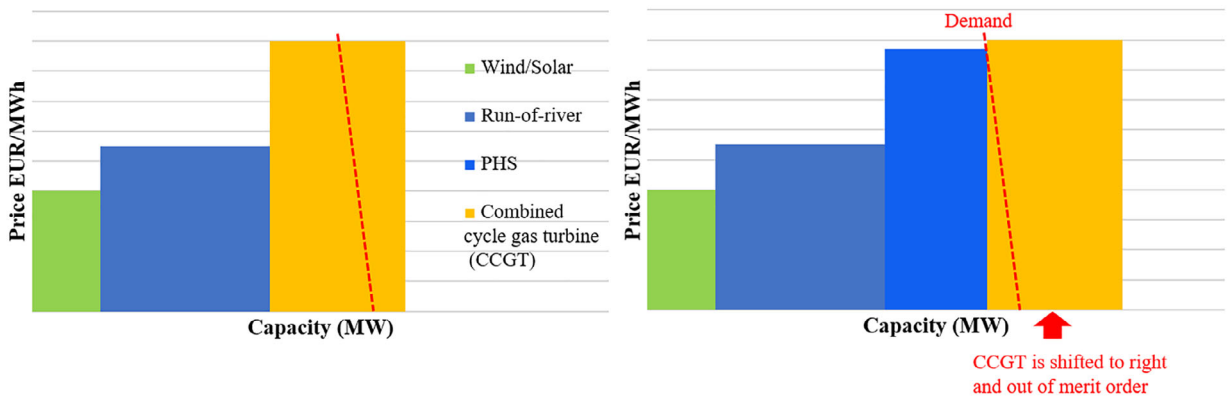

FIGURE 7 Merit order curve without (left) and with pumped hydro storage (right) under "normal" dispatch

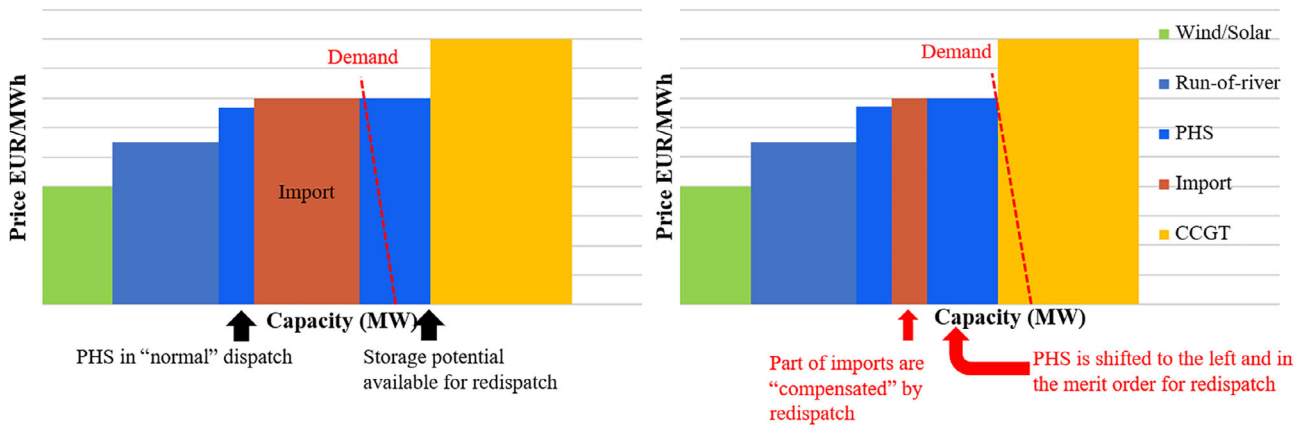

FIGURE 8 Merit order curve, including a significant amount of imports of electricity from VARET under "normal dispatch" (left) and "redispatch" (right) as a need to release grid congestion

Equation (5) explains when—as illustrated in Figure 7—pumped hydro storage is more cost-effective than a combined cycle gas turbine (CCGT). Under redispatch, however, another factor besides the (shadow) price, namely which one of the two power plants is geographically "closer" to the bottleneck of the physical grid infrastructure, plays an important role.

$$\begin{aligned} &\text{IF}\left(\frac{\text{IC}_{\text{STO}}\cdot\text{CRF}}{T_{\text{STO}}}+\frac{P_{\text{ELE}}}{\eta_{\text{STO}}}\right)<\left(\frac{\text{IC}_{\text{GT}}\cdot\text{CRF}}{T_{\text{GT}}}+\frac{P_{\text{GAS}}}{\eta_{\text{GT}}}\right)\\ &\text{THEN->Invest into storage}\\ &\text{ELSE->Invest into CCGT} \end{aligned} \tag{5}$$

with:

IC_{STO}: storage investment costs (€)
IC_{GT}: investment costs of a CCGT (€)
T_{STO}: full-load hours of storage (hours/year)
CRF: capital recovery factor (1/year)
P_{ELE}: electricity market price (€/kWh)
η_{STO}: storage efficiency
T_{GT}: full-load hours of CCGT (hours per year)
P_{GAS}: market price of natural gas (€/kWh)
η_{GT}: efficiency of CCGT

5.2 | Hydrogen as a storage

It is also possible to use the energy carrier hydrogen as long-term storage for surplus electricity generated by VARET. In this case, in times of excess capacity, hydrogen can be produced in electrolysis systems, storing electricity in the long run. So far, almost solely low-capacity (lower than 500 kW) have been deployed. But some large plants with electrolyzers are also already installed (e.g., in Béancour, Canada a 20 MW PEM electrolyzer (Platts, 2021), a 10 MW alkaline electrolyzer in Fukushima, Japan (IRENA, 2020), with intentions for constructing additional capacity in the near future. Worldwide, following the (IEA, 2020b) additional 48,000 MW are considered to operate until 2040. The projects with the biggest size are planned in Australia (Asian Renewable Energy Hub, Murchison), Italy (Silver Frog), and the Netherlands (North H2 green hydrogen). This will significantly lower the production costs of hydrogen, compare Figure 9.

Eventually, the cost-minimal relation between size-dependent capital costs of the electrolysis plant and actual yearly full-load hours is important. For instance, Figure 9a depicts the total production costs from large decentralized electrolysis plants depending on the yearly full-load hours and the electricity costs as seen in Figure 4 and Table 4. Reasonable hydrogen costs of about 12 cents/kWh might be achieved at 5000 full-load hours per year and higher.

In contrast to Figure 9a, Figure 9b shows the total production cost in a big electrolyzer again based on the total amount of full-load hours. For this large plant, the reasonable minimal hydrogen production costs are between 8 and 9 cents/kWh. They could come about from yearly full-load hours of some 4500 h/year.

5.3 | Battery storage

As mentioned above, also decentralized batteries could be important in the overall energy system. Their investment and storage costs are not expected to go down much more rapidly than those of hydrogen but finally, they will compete with the household electricity price being (and remaining) significantly higher.

For different uses also, specific storage solutions are required. In the current battery storage market, technologies based on lithium are prevailing.

Figure 10 documents the evolution of different stationary Li-Ion storage energy costs between 2013 and 2020. Especially in the last 7 years, investment costs of battery packs remarkably decreased. A major reason for these cost

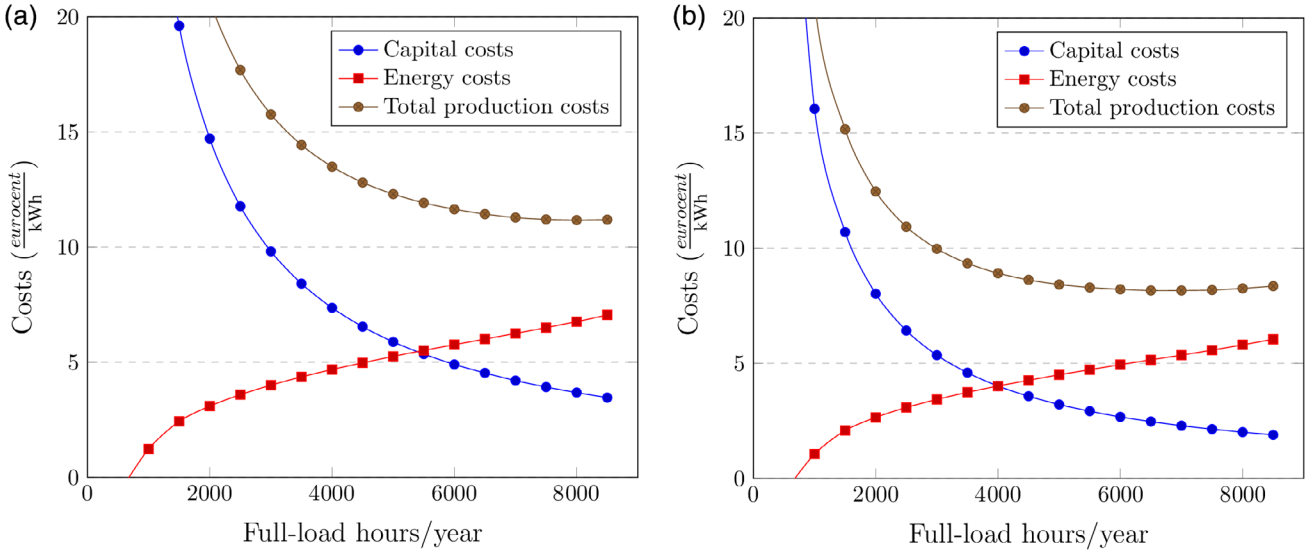

FIGURE 9 (a) Hydrogen production costs in a large electrolysis plant with 500 kW_ele capacity depending on the yearly full-load hours. (b) Hydrogen production costs in a centralized big electrolysis plant with 10 MW_ele capacity depending on the yearly full-load hours

reductions was the remarkable capacities that have been deployed for manufacturing batteries for electric vehicles. Tsiropoulos et al., 2018 highlight that the costs of Li-ion battery vary substantially depending on impact factors such as physical limits (e.g., grid connection), system (e.g., utility, behind-the-meter), operation category (e.g., peak shaving, frequency control), the system scale and chemistry, which are not always properly stated in the literature. This makes it very hard to find adequate price estimates for Li-ion batteries

In Figure 10, we base the cost development of different Li-ion storage systems on the price index of the respective storage technology published by ees Europe (2020). The costs for the Li-ion residential stationary batteries and Li-ion stationary storage systems were derived from Tsiropoulos et al. (2018) and the costs for the Li-ion battery pack from BloombergNEF (2019). The battery pack is, according to Tsiropoulos et al. (2018) the storage module and includes the rack/tray frame/cabinet, battery management system, and the battery modules. As residential stationary batteries, we considered behind-the-meter batteries below 10 kWh, which include the storage module and the balance of the system (container, monitor and controls, thermal management, and fire suppression). For stationary storage systems, we used the price for storage capacities up to 30 kWh and they include besides all components of residential stationary batteries

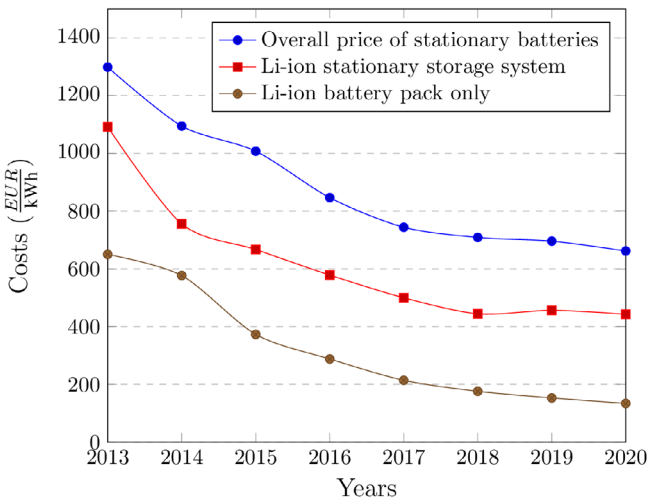

FIGURE 10 The development of costs of li-ion based stationary battery system from 2013–2020 (own calculations, data based on Tsiropoulos et al., 2018, BloombergNEF, 2019 and ees Europe, 2020)

also the power transfer system (inverter, switches and breakers, and energy management system) and the construction (Tsiropoulos et al., 2018).

Government policies for large battery rollouts also helped to decrease the price. As an example, Australia and California considerably increased their behind-the-meter energy storage capacity with different incentive programs. The total household storage capacity surpassed 1 GWh in Australia, to which mainly the Next Generation Energy Storage project, as one of the largest rollouts worldwide, contributed. Australia has also been leading regarding large-scale battery storage rollouts as the first worldwide 100-MW lithium-ion storage was built in 2017 by Tesla (BBC, 2017). California allocates 80% of the $1.2 billion budget of the Self-Generation Incentive Program for storage incentives, which also substantially boosts the battery storage capacity. Today's largest battery storage projects Moss Landing Energy Storage Facility (300 MW) and Gateway Energy (230 MW), are installed in California (Energy Storage News, 2021b, 2021a).

Besides Australia and the United States (California), IRENA (2019) defines Germany, Japan, and the United Kingdom as key regions for large-scale batteries. Table 5 lists some selected large-scale battery storage systems in operation worldwide. Several additional large-scale projects are underway.

Currently, BEVs are seen as a potential driver for making stationary batteries cheaper. Yet, this strongly depends on which cost component (package, frames, inverters, Lion cells, charging controllers, thermal management systems, installation costs) is included in the comparison and considered in overall investment cost figures and what is missing and neglected (Mitchell et al., 2017). In Figure 11, the medium investment costs of lithium ion batteries for consumers in 2013 and 2019 in Germany are illustrated. It is obvious from this figure that the investment costs of stationary battery storage have decreased remarkably, especially for common sizes used in one-family houses with a usual battery size of 1 kWh up to 7 kWh. These remarkable economies of scale of household-size capacities are caused mainly by the fact that the number of small battery storage systems has risen on the market in the last decade more than the larger systems. In addition, competition between several manufacturers has been intensified, see for example, the work conducted by Munuera and Alberto (2020). Moreover, it is also the size category with the largest number of available single data. The number of battery storage installed with systems of capacities higher than 15 kWh has been smaller so that the degression in investment costs is difficult to identify.

6 | THE VALUE OF STORAGE FOR SOCIETY

In this chapter, we explain the concept of welfare effects of storage and give an overview of the academic literature in this respect.

Ehlers (2011) defines the welfare effects of storage as the sum of all external effects caused by it. He calculated those by combining the supply and demand curves of each hour into a net curve. By plotting net curves for the time of "storage in" and "storage out" he shows the resulting price differences as displayed in Figure 12. The overall welfare is generally divided into producer, consumer and storage surplus, the latter being the storage operator's contribution margin (CM). The conclusion of this analysis is that quite high welfare gains can be achieved. By applying a real example, he shows that in the year 2009 when adding 2000 MW (8 h) of additional pumped hydro storage, additional welfare gains of about 23 Mio. Euro and about 25 Mio. Euro of CMs on the spot market might be achievable. Any investor nevertheless will limit the additional storage investment to the level of the maximal CM, as for him, only the CM (storage surplus) is relevant. In case of full competition, additional investors enter the market up to the break-even point in order to get the remaining welfare profits. The conclusion derived by Ehlers (2011) is that this is actually not typically because of specific risks from the investor's viewpoint (e.g., evolution of investment costs of storage and also of competing

TABLE 5 Selected large-scale battery storage systems (Energy Storage News, 2021a and b; IRENA, 2019)

Name of project	Capacity (MW)	Country	Service provided
Moss landing energy storage facility	300	USA	Capacity firming
Gateway energy storage (LS power)	230	USA	Capacity firming
Hornsdale power reserve (Tesla)	100	Australia	Frequency regulation, capacity firming
STEAG battery storage	90 (distributed over 6 sites)	Germany	Frequency regulation
Terna sodium-sulfur battery	38.4	Italy	Grid investment deferral, reduced RE curtailment

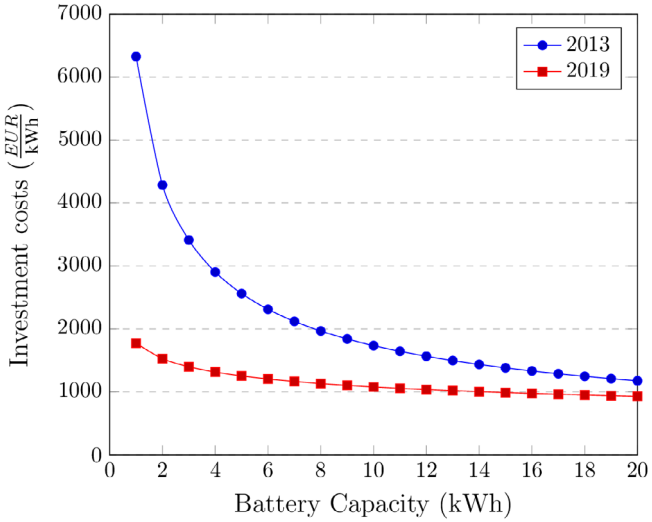

FIGURE 11 Development of the economies-of-scale of small battery storage with capacities between 1 and 20 kWh for 2013 and 2019 (own calculations based on Hiesl et al., 2020, using data from C.A.R.M.E.N., 2019)

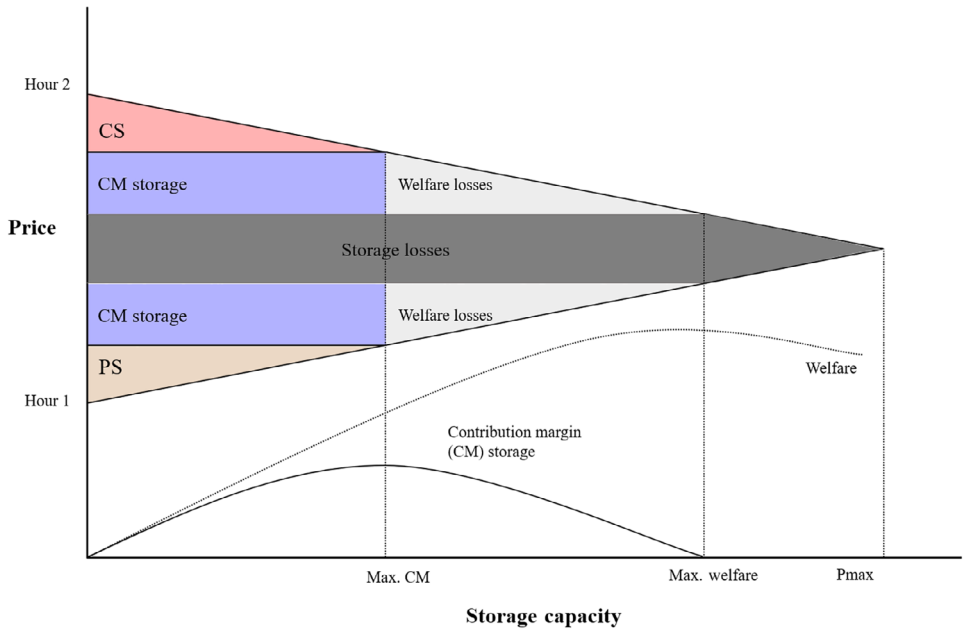

FIGURE 12 Welfare effects of storage with CS=consumer surplus, CM=contribution margin and PS=producer surplus (Ehlers, 2011)

alternatives, see discussion in next section). Investors will act cautiously and therefore, all the theoretically possible welfare gains will never be exhausted by private-sector investments alone (Ehlers, 2011).

Storage is being widely promoted by policy makers without discussing the economic value aspects linked to this development. Despite this, the academic literature is modeling certain implications of storage, from an increase of overall welfare to reduced welfare under different market-structure conditions and the effects on social welfare.

The first analysis assuming perfect competition on the relations between economics and welfare effects has been conducted by Sioshansi et al. (2009). They present a maximization of the social welfare model and conclude that despite the arbitrage value being reduced because of the smoothening impact of large-scale storage on the price, other social welfare improvements can be brought about (e.g., better use of the infrastructure in the whole electricity system, reduction of congestion, less need to build power plants as well as lower demand for new transmission and distribution lines). Due to the induced load and price shifting, massive wealth transfers occur with a significant increase in consumer surplus. Schill and Kemfert (2011) show that the same also applies in an oligopolistic market.

Sioshansi (2010) examines different ownership structures and shows the potential welfare effects. The key finding is that consumers usually overuse storage, while traders and generators tend to underuse their assets in order to retain a greater price gap between on-and off-peak prices in comparison to the optimal solution for social welfare since they lack sufficient incentives to operate the storage in a way to maximize social welfare.

The model of Crampes and Moreaux (2010) analyzes an optimal deployment of a pumped hydro storage- and a thermal plant and finds that transferring a surplus in social welfare from times with high demand to times of low demand can create a net social gain under perfect competition.

Schill and Kemfert (2011) find that the use of storage technologies related to welfare is based on the capacity of the storage to introduce market power with actual German pumped hydro storage data. For several reasons, the parallel use of different storage and fossil plants may lead to a lower producer surplus compared to a situation without using storage. However, in every scenario, overall social welfare rises despite some price-smoothing effects of storage, reducing the producer surplus. The lowest welfare levels are in an oligopolistic market. They find that an oligopolistic market is not likely for the current market situation in Germany. Another important result is that investments in additional storage are not appealing to players who already own other generation plants, as in other scenarios, the producer surplus is less than if there were no storage capacities available. Storage's price-smoothening effect reduces the profits of fossil generation if storage is added.

Introducing a market with high penetration of wind energy Sioshansi (2011) describes with data of Texas that adding a new storage capacity to a not perfect competitive electricity market may result in a net reduction of social welfare when opposed to a non-storage scenario. Sioshansi (2014) models different ownership and market structures with a stylized equilibrium model and finds that storage can decrease welfare relative to the non-storage situation in markets with strategic generating firms. In the case that those storage operations are perfectly competitive, the welfare losses can even be greater. Siddiqui et al. (2019) have extended this model and explore the effects of storage on social welfare assuming an imperfectly competitive generation sector including investments in additional storage units. They assume that either the storage capacity is owned by a profit-maximizing standalone merchant investor or a welfare-maximizing storage operator and find that the latter only invests in more storage capacity than a profit-maximizing firm if the generation sector is relatively imperfectly competitive. If the market case is sufficiently competitive, the investor maximizing the profits from storage operation may decline welfare compared to a situation with no storage, which is opposite to the result of Sioshansi (2014).

Karaduman (2020) includes the channel of responding to price changes of incumbent generators. He argues that including this is essential for large-scale storage and is also in line with the findings of Ehlers (2011) that additional storage operators decrease the price spread and the profitability might be overestimated, as discussed in greater depth in the following part.

7 | ISSUES OF RENEWABLE GENERATION PEAKS AND THE ROLE OF ADDITIONAL STORAGE

The issue of whether every additional peak generated from VARET has to be stored has been analyzed in several papers. Schill (2014) models different storage capacities that are required for VARET integration. He finds that already a small percentage of curtailment has a substantial effect on the required additional storage capacity, given that alternative flexibility options are available in the respective electricity system.

Besides different storage options, also transmission network extensions, technical demand-side measures, demand response alternatives, and smart grids are a part of the solution depending on the requirements, leading to increased competition and decreasing profit for storage operators, see Figure 13.

Lund et al. (2015) and Zöphel et al. (2018) give a thorough and informative review of all possible options. Müller and Möst (2018) outline demand-side possibilities to balance short-term volatility in the residual load curve. According to Haas and Auer (2019) the key to balancing fluctuations in the residual load is to incorporate an efficient portfolio of measures for increasing flexibility solutions that are already available. Other important options besides the energy storage option discussed in this work are the following:

- Extensions of the transmission network lead evening out load profiles as well as generation profiles;
- Technical demand-side measures implemented by electric utilities such as load management, for example, of air-conditioning systems and cycling;

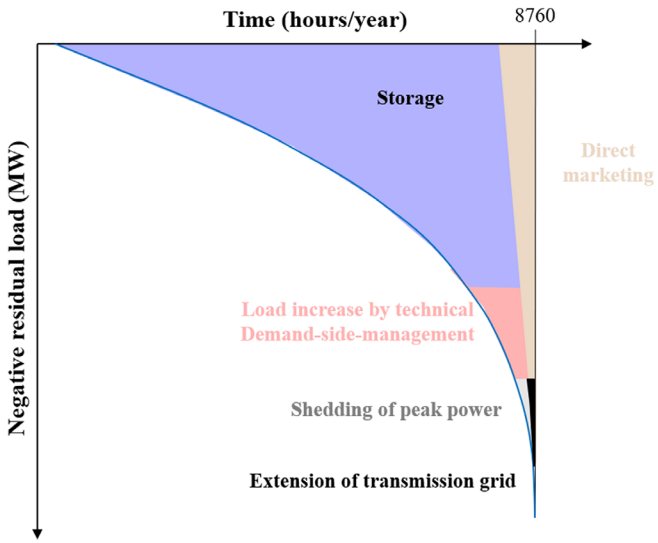

FIGURE 13 Options for flexible use of excess electricity competing with storage (adapted from Hiesl et al. (2020)

- Demand response because of time-of-use prices especially addressing large customers;
- Smart grids: This technical option offers opportunities to switch between different voltage levels and allow additional load balancing.

Extension of the transmission grid extension is the most important option, as it provides a remarkable significant contribution for integration of larger amounts of electricity from VARET as shown by Burgholzer and Auer (2016). Additionally, they analyze different scenarios up to 2050 in Austria and find that the deployment of new transmission systems such as flexible AC and dynamic line rating can contribute to reducing the shedding of electricity from VARET considerably.

Regarding possible demand-side management options, Zweifel et al. (2017) point out that today mostly constant end-user electricity prices (regardless of the magnitude of the wholesale price) for smaller customers are offered by power retailers in combination with a delay of smart meter rollout, making it very hard to apply adequate demand response options especially. Further, they recommend flexible tariffs in view of the growing energy from VARET being integrated into the system.

Another important flexibility aspect is the PtG option for surplus energy (no re-electrification), as highlighted by Schill (2020). Through the coupling of the electricity sector to others, we can try other types of storage, including electricity in transport (smart charging) and heating (direct resistive, heat pumps). Vehicle-to-grid technology can additionally play an active role in resolving bottlenecks in the transmission grids and saving on redispatch costs, as shown by Staudt et al. (2018). Additionally, electric vehicle owners can receive compensation for the flexibility provided to the power system.

However, not all mentioned options are in perfect competition to each other due to differences in long-or short-term flexibilities provided. Some storage technologies provide more long-term flexibility as for example, demand-side management or geographical balancing, which depends on the balancing area. The power sector coupling can use excess electricity but in general it no re-electrification takes place (Schill, 2020).

In the previous sections, the economics of storage were shown from the perspective of the current baseline VARET integration scenario. However, as soon as larger amounts of VARET are integrated, the residual load curve and storage deployment change, as discussed in Schill (2020) and Prol and Schill (2020). Next, the impact of added storage capacity in a high VARET scenario on the market price will be discussed.

In Figure 14, Zach and Auer (2016) show the residual load curve for the CWE- region (Central Western Europe) (Austria, Belgium, France, Germany, Luxembourg, Switzerland, The Netherlands, and West Denmark) modeled for the Blue storyline within an EU-project (SUSPLAN). In this storyline, it is assumed that remarkable growth rates for VARET take place, combined with the high assumed growth of electricity demand. Additionally, Figure 14 depicts the existing thermal power plant and pumped hydro storage capacity and shows the capacity gap of about 35 GW for the year 2030.

Looking at the distribution of the residual load in a scenario with high shares of VARET, analyzed over the 8760 h of a year and classifying it by its magnitude gives finally, a curve depicted in Figure 15. From this graphic, it can be seen that there are more than 2000 h with surplus electricity due to excess production mainly from VARET. On the very right side in this figure, it is a steep peak, indicating that huge excess capacity is only present at some hours. This characteristic leads to the question of how much of the excess electricity seen in this graph should be stored indeed and used in hours when there is a lack of electricity. The problem of decreasing full-load hours is prevalent in this scenario. It shows that every storage added to an electricity system has lower full-load hours than the ones before and hence is less

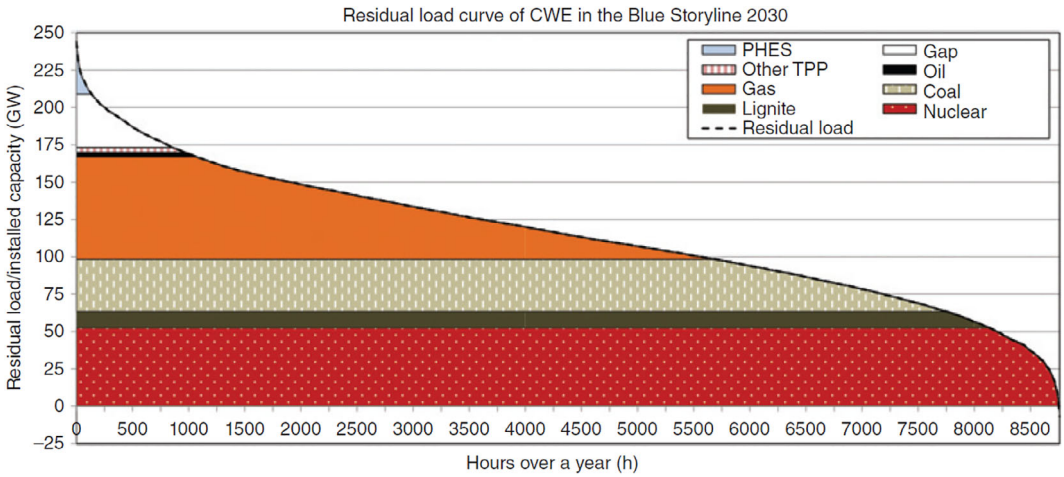

FIGURE 14 How the residual load in a specific region (CWE) is met by existing conventional power capacities & pumped hydro storage in the blue storyline (Zach & Auer, 2016)

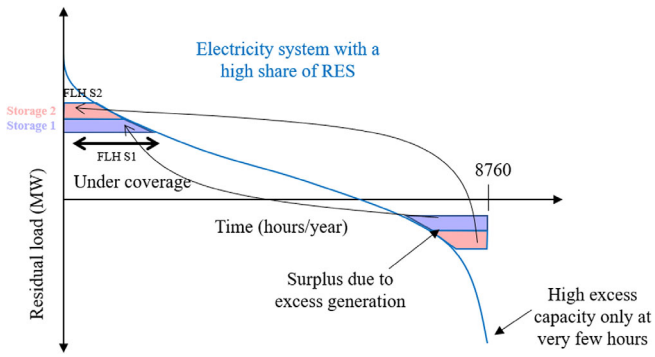

FIGURE 15 Full-load hours of additional storage options within a load duration curve with large shares of electricity from VARET

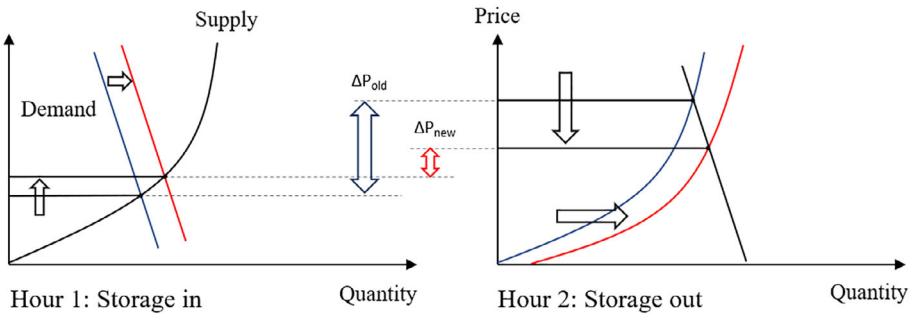

FIGURE 16 Impact of a new storage capacity on the price spread (Δp) in the wholesale market (Ehlers, 2011)

competitive from an economic point of view. Schill (2020) recommends supplying the peak load with dispatchable generation as it is less costly. In general, they conclude that storage provides only a small contribution to meet residual electricity peak load in the current and near-future energy system.

This results in the statement that each new storage deployed in addition to the existing ones makes the price spread smaller, see Figure 16, and, hence, reduces its own economic benefits. In this scenario, the demand increases in hour one when the electricity is being stored; hence the market price increases as well. Within the hour, the electricity is delivered back to the network; however, the use of storage decreases the market price (Ehlers, 2011). This effect, however only applies if the supply curve is convex in the case of an S-shaped curve (e.g. through the market design of high negative electricity prices), the use of storage can also result in a rising price level.

8 | PERSPECTIVES FOR THE ECONOMICS OF SEVERAL STORAGE TECHNOLOGIES UP TO 2050

The actual economic performance of the long-term storage options examined in this work is not competitive with pumped hydro storage, as see in Figure 3. However, in the future the prospects could improve, mainly due to technological learning, which could cut the investment costs of long-term storage (see e.g., European Commission, 2012; IEA, 2000; McDonald & Schrattenholzer, 2002). These prospects are analyzed in the following. Amounts over time for the different technologies are assumed using IEA figures. Yet, for pumped hydro storage, no further effects of Technological Learning are taken into account because it is assumed as an already fully mature type of technology. For the other technologies, we model technological learning by using learning rates. Equation (6) is used to describe an experience curve:

$$IC_{New}(x_t) = IC(x_{t_0}) \cdot \left(\frac{x_t}{x_{t_0}}\right)^{-b} \tag{6}$$

where IC_{New} represents the cost for the investment in the new parts of the technology at t, b is the learning index, while IC_0 states the investments at t_0. Finally, x is the amount manufactured cumulative until time t, respectively, t_0 for a single type of storage type at t and Figure 17 depicts the scenarios developed for the investment expenses of several electricity storage variants, using specific learning rates of 20%, (see e.g., Nykvist & Nilsson, 2015). For pumped hydro

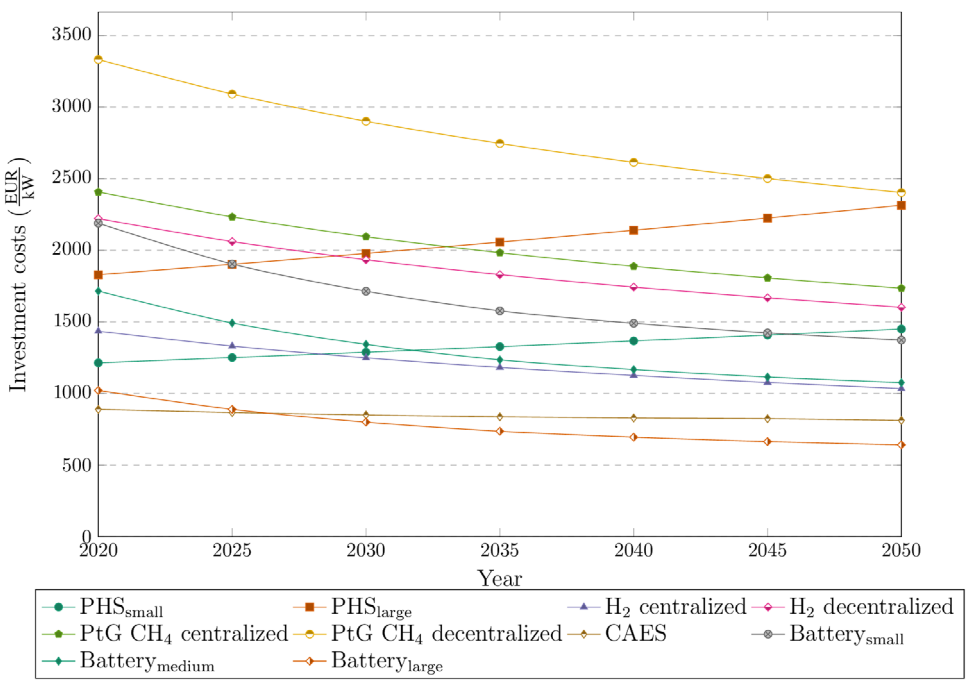

FIGURE 17 Future prospects for investment costs of several storage technologies with learning rates of 20%

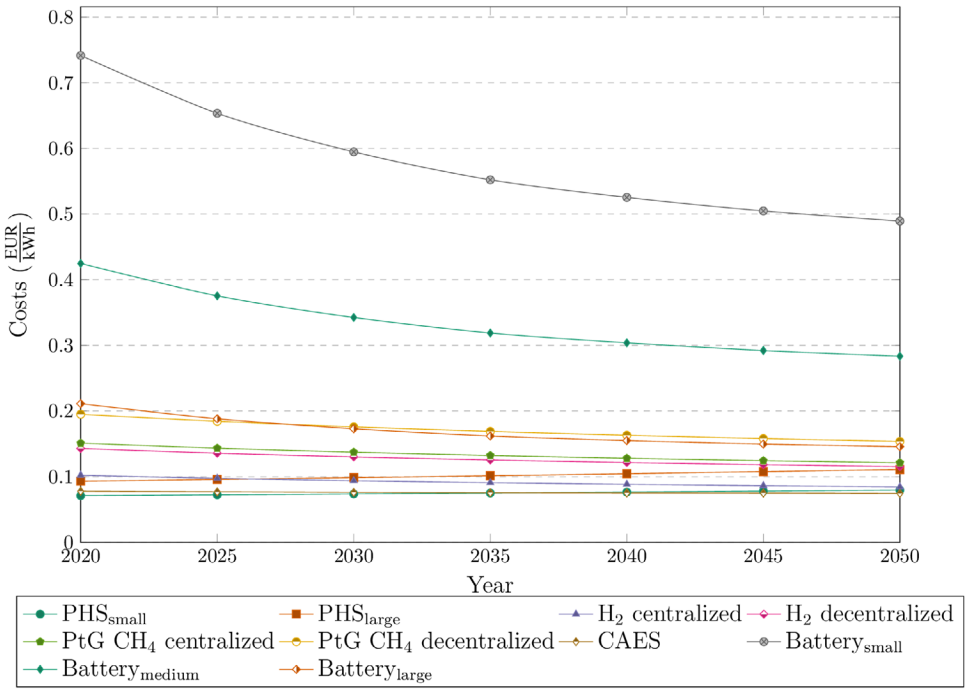

FIGURE 18 Perspectives for the costs of storing electricity with different storage technologies until the year 2050 (corresponding full-load hours as documented in Table 3)

storage, the learning effects are essentially neglected as it is already a very highly developed technology where further learning effects are difficult to obtain. Furthermore, prices for long-term pumped hydro storages are more likely to continue to rise, mainly due to the lack of sites with reasonable costs and lack of acceptance. For CAES power plants, only moderate effects are assumed since the quantities in the next few years are very uncertain and it is not very clear whether any more of these power plants will be built on a significant scale. On the contrary, it is to be expected that the prices of PtG and battery technologies will fall in the period up to 2050, mainly due to learning effects combined with mass production, standardization as well as spillovers. This is supported by IEA (2020a), projecting high learning rates not only for batteries but for other small, simple, modular, and adaptable designs such as electrolyzers and fuel cells. These were produced only in small volumes so far, yet, there are expectations for faster growth in the next ten years.

All large systems for storing electricity with different storage technologies until the year 2050 would eventually be much too expensive to be viable in a dynamic market environment. For hydrogen & methane, the costs—given 2000 full-load hours per annum—would be in a range of about 0.09 and 0.17 EUR/kWh, respectively, in 2030, given very favorable opportunities for technological learning (see IEA, 2020a; Figure 18).

9 | CONCLUSIONS

The following are the main conclusions:

On the one hand, regarding the economic performance of storage in wholesale electricity markets, the major parameters are the price spread between purchase and selling price, see Figure 16 and the full-load hours related, showing the incentive for arbitrage. If the CO_2 prices were high enough to raise electricity market prices remarkably at times of scarce electricity, this would improve the economic prospects. Moreover, another important aspect is the grid fee for storing and discharging. While there are some calls that storage has to be considered as a system component and not a direct customer, it has to be borne in mind that also in wholesale markets, other options for flexibility exist and these would face distortions if storage would be treated with preference. Hence, excluding storage from network charges might bias the spot market. Related to this issue, Sioshansi (2011) emphasizes the relevance of a suitable market design, which should in addition increase the incentives for proper storage operation.

On the other hand, the costs of storing electricity in decentralized battery storage depend heavily on the amounts of cycles, a synonym to full-load hours, as well as the related final prices for electricity (considering all possible fees and

taxes). These decentral operators working "behind the meter" must not be concerned about low margins in the spot markets and that they are not dealing with low wholesale price margins but rather with slightly higher retail electricity prices. In general, retail electricity rates are considerably higher, with 20 to 30 cents/kWh in Western Europe. This does not apply to countries like Germany as their household electricity prices are substantially higher than in the European average, making decentralized storage more economically viable. Nevertheless, the current purpose of small battery storage is to store electricity from PV, with a limited energetic efficiency with few full-load hours, especially in winters, being a major economic barrier.

To summarize the specifics of the three storage options that were discussed in detail:

i. as far as pumped hydro storage is concerned, the most critical aspect is that their investment costs will not be substantially reduced in the future due to no major additional learning effects and the fact that the cheapest location plants are already deployed;
ii. while stationary decentralized batteries may clearly increase the potential for own usage of electricity when connected to PV systems, the main drawback is, that none-the-less battery purchase costs have been falling in the last decade, and their rather full-load hours remain leading to rather moderate economic efficiencies. Due to the overall development of batteries, it is clear that their prices will further drop in the future, yet it is uncertain to which level. Additionally, the effect they have on the overall energy system has to be further investigated;
iii. in the case of PtG options like hydrogen and methane, despite strong technical technological learning potential, it will become tough for them to compete in the wholesale markets when the energy-related storage costs are high. The key explanation is poor round-trip efficiency, which might result in high generation costs for electricity.

In addition, it is important to state that aside from storage also other flexibility measures exist. Storage is competing with new network lines, load management and others. That is to say, from technical as well as economic viewpoints, all options available have to be taken into account at the same time. A slightly different point-of-view in favor of storage operation is presented by Geske and Green (2020). They ask, "Will current electricity markets design give the right incentives for storage?" and state that "storage can be seen as arbitrage against the occasional risk of extreme prices when load might be lost." However, of core relevance is that new storage capacities are to be built in a tuned way with the deployment of VARET indicating that new excess generation is looming from these sources.

Furthermore, regarding very short-term electricity production to meet residual load peaks, natural gas-fueled power plants are a flexible but not entirely carbon-free option. Consequently, considering the economic assessment of the storage of electricity, all potential competing alternatives must be considered at the same time. New storage capacity should, at any rate, be built only if a strong indication of new surplus generation by VARET is proven and if it is done in a coordinated approach step-by-step with the construction of VARET power plants.

ACKNOWLEDGMENTS

The authors would like to thank Wolf-Peter Schill for helpful comments.

CONFLICT OF INTEREST

The authors have declared no conflicts of interest for this article.

AUTHOR CONTRIBUTIONS

Reinhard Haas: Conceptualization (equal); data curation (equal); formal analysis (equal); methodology (equal); validation (equal); writing – original draft (equal); writing – review and editing (equal). **Claudia Kemfert:** Conceptualization (equal); methodology (equal); validation (equal); writing – review and editing (equal). **Hans Auer:** Conceptualization (equal); methodology (equal); validation (equal); writing – original draft (equal); writing – review and editing (equal). **Amela Ajanovic:** Data curation (equal); formal analysis (equal); validation (equal); writing – original draft (equal); writing – review and editing (equal). **Marlene Sayer:** Data curation (equal); formal analysis (equal); validation (equal); writing – original draft (equal); writing – review and editing (equal). **Albert Hiesl:** Validation (equal); writing – original draft (equal); writing – review and editing (equal).

ORCID

Reinhard Haas https://orcid.org/0000-0001-9361-3452

RELATED WIREs ARTICLES

On the long-term prospects of power-to-gas technologies

REFERENCES

Ajanovic, A., & Haas, R. (2014). *On the market prospects of long-term-electricity storages*. https://www.biee.org/resources/on-the-market-prospects-of-long-term-electricity-shortages/

Ajanovic, A., & Haas, R. (2019). On the long-term prospects of power-to-gas technologies. *WIREs Energy and Environment*, *8*, e318. https://doi.org/10.1002/wene.318

Ajanovic, A., Hiesl, A., & Haas, R. (2020). On the role of storage for electricity in smart energy systems. *Energy*, *200*, 117473. https://doi.org/10.1016/j.energy.2020.117473

Amirante, R., Cassone, E., Distaso, E., & Tamburrano, P. (2017). Overview on recent developments in energy storage: Mechanical, electrochemical and hydrogen technologies. *Energy Conversion and Management*, *132*, 372–387. https://doi.org/10.1016/j.enconman.2016.11.046

Baumann, C., Schuster, R., Moser, A., (2013). Economic potential of power-to-gas energy storages, in: 2013 10th International Conference on the European Energy Market (EEM). 2013 10th International Conference on the European Energy Market (EEM 2013), Stockholm, Sweden. IEEE, pp. 1-6.

BBC. (2017). Tesla mega-battery in Australia activated. *BBC News*.

Behabtu, H. A., Messagie, M., Coosemans, T., Berecibar, M., Anlay Fante, K., Kebede, A. A., & van Mierlo, J. (2020). A review of energy storage technologies' application potentials in renewable energy sources grid integration. *Sustainability*, *12*, 10511. https://doi.org/10.3390/su122410511

Bloess, A., Schill, W.-P., & Zerrahn, A. (2018). Power-to-heat for renewable energy integration: A review of technologies, modeling approaches, and flexibility potentials. *Applied Energy*, *212*, 1611–1626. https://doi.org/10.1016/j.apenergy.2017.12.073

BloombergNEF. (2019). Low-cost batteries are about to transform multiple industries. *Forbes*, *2019*. https://www.forbes.com/sites/robday/2019/12/03/low-cost-batteries-are-about-to-transform-multiple-industries/?sh=679929161054

Böcker, B., Steffen, B., & Weber, C. (2015). Photovoltaics and storage plants. In B. Sørensen (Ed.), *Solar energy storage* (pp. 209–223). Elsevier.

Böhm, H., Zauner, A., Rosenfeld, D. C., & Tichler, R. (2020). Projecting cost development for future large-scale power-to-gas implementations by scaling effects. *Applied Energy*, *264*, 114780. https://doi.org/10.1016/j.apenergy.2020.114780

Bünger, U., Michalski, J., Crotogino, F., & Kruck, O. (2016). Large-scale underground storage of hydrogen for the grid integration of renewable energy and other applications. In *Compendium of Hydrogen Energy* (pp. 133–163). Elsevier.

Burgholzer, B., & Auer, H. (2016). Cost/benefit analysis of transmission grid expansion to enable further integration of renewable electricity generation in Austria. *Renewable Energy*, *97*, 189–196. https://doi.org/10.1016/j.renene.2016.05.073

C.A.R.M.E.N. (2019). EV: Marktübersicht Batteriespeicher, 2013,2016,2019.

Crampes, C., & Moreaux, M. (2010). Pumped storage and cost saving. *Energy Economics*, *32*, 325–333. https://doi.org/10.1016/j.eneco.2009.10.004

Dallinger, B., Schwabeneder, D., Lettner, G., & Auer, H. (2019). Socio-economic benefit and profitability analyses of Austrian hydro storage power plants supporting increasing renewable electricity generation in Central Europe. *Renewable and Sustainable Energy Reviews*, *107*, 482–496. https://doi.org/10.1016/j.rser.2019.03.027

Dawood, F., Anda, M., & Shafiullah, G. M. (2020). Hydrogen production for energy: An overview. *International Journal of Hydrogen Energy*, *45*, 3847–3869. https://doi.org/10.1016/j.ijhydene.2019.12.059

Deane, J. P., Gallachóir, B. P. Ó., & McKeogh, E. J. (2010). Techno-economic review of existing and new pumped hydro energy storage plant. *Renewable and Sustainable Energy Reviews*, *14*, 1293–1302. https://doi.org/10.1016/j.rser.2009.11.015

DOE. (2020). *Global energy storage database*. Sandia National Laboratories. https://www.sandia.gov/ess-ssl/global-energy-storage-database-home/

Duffner, F., Kronemeyer, N., Tübke, J., Leker, J., Winter, M., & Schmuch, R. (2021). Post-lithium-ion battery cell production and its compatibility with lithium-ion cell production infrastructure. *Nature Energy*, *6*, 123–134. https://doi.org/10.1038/s41560-020-00748-8

EASE. (2021). Energy storage technology descriptions. https://ease-storage.eu/energy-storage/technologies/

Eckhouse, B., & Stringer, D. (2021). *A megabattery boom is coming to rescue overloaded power grids*. Bloomberg. https://www.bloomberg.com/news/articles/2021-01-22/megabattery-boom-will-rescue-overloaded-power-grids

ees Europe. (2020). Marktinformationen – ees Europe. https://www.ees-europe.com/de/fuer-aussteller/warum-teilnehmen/marktinformationen?langNav=1&print=1&sysLanguageIsocode=de&cHash=2ee4f2ea3189c5a2e2a167e3b7effd54

Ehlers, N. (2011). *Strommarktdesign angesichts des Ausbaus fluktuierender Stromerzeugung* [Dissertation].

Energy Storage News. (2021a). Amid California's heatwaves and fires, 'world's largest' battery project is being switched on. https://www.energy-storage.news/news/amid-californias-heatwaves-and-fires-worlds-largest-battery-project-is-bein (Accessed 1 March 2021).

Energy Storage News. (2021b). At 300MW/1,200MWh, the world's largest battery storage system so far is up and running. https://www.energy-storage.news/news/at-300mw-1200mwh-the-worlds-largest-battery-storage-system-so-far-is-up-and (Accessed 1 March 2021)

Erbach, G. (2019). *Energy storage and sector coupling*. EPRS|European Parliamentary Research Service.

European Commission. (2011). Electrical energy storage, White paper, IEC.

European Commission. (2012). Technology learning curves for energy policy support.

Eurostat. (2014). Energy, transport and environment indicators KS-DK-14-001-EN-N S123: 2014 edition.

Eurostat. (2021). Electricity and heat statistics. https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Electricity_and_heat_statistics#Production_of_electricity

Fan, X., Liu, B., Liu, J., Ding, J., Han, X., Deng, Y., Lv, X., Xie, Y., Chen, B., Hu, W., & Zhong, C. (2020). Battery technologies for grid-level large-scale electrical energy storage. *Tianjin University*, *26*, 92–103. https://doi.org/10.1007/s12209-019-00231-w

Ferreira, H. L., Garde, R., Fulli, G., Kling, W., & Lopes, J. P. (2013). Characterisation of electrical energy storage technologies. *Energy*, *53*, 288–298. https://doi.org/10.1016/j.energy.2013.02.037

Fu, R., Remo, T., & Margolis, R. (2018). U.S. utility-scale photovoltaics plus-energy storage system costs benchmark.

Fuchs, G., Lunz, B., Leuthold, M., & Sauer, D. U. (2012). Technology Overview on Electricity Storage – Overview on the potential and on the deployment perspectives of electricity storage technologies, p. 67.

Gatzen, C. (2008). *The economics of power storage: Theory and empirical analysis for Central Europe* [Zugl.: Köln, Univ., Diss.]. Oldenbourg-Industrieverl., München, p. 227.

Geske, J., & Green, R. (2020). Optimal storage, investment and management under uncertainty: It is costly to avoid outages! *The Energy Journal*, *41*. 1–28. https://doi.org/10.5547/01956574.41.2.jges

Greim, P., Solomon, A. A., & Breyer, C. (2020). Assessment of lithium criticality in the global energy transition and addressing policy gaps in transportation. *Nature Communications*, *11*, 4570. https://doi.org/10.1038/s41467-020-18402-y

Haas, R., & Ajanovic, A. (2013). Wirtschaftliche und energetische Aspekte von Langzeitspeichern. *Elektrotechnik und Informationstechnik*, *130*, 169–176. https://doi.org/10.1007/s00502-013-0150-4

Haas, R., & Auer, H. (2019). On new thinking and designs of electricity markets. In R. Haas, L. Mez, & A. Ajanovic (Eds.), *The technological and economic future of nuclear power* (pp. 369–385). Springer Fachmedien Wiesbaden.

Härtel, P., Doering, M., Jentsch, M., Pape, C., Burges, K., & Kuwahata, R. (2016). Cost assessment of storage options in a region with a high share of network congestions. *Journal of Energy Storage*, *8*, 358–367. https://doi.org/10.1016/j.est.2016.05.010

Havranek, F. (2012). *Pumpspeicherkraftwerke als zentraler Baustein der Energiewende: Eine Wirtschaftlichkeitsanalyse für das deutsche und österreichische Marktgebiet* [Diplomarbeit].

Hiesl, A., Ajanovic, A., & Haas, R. (2020). On current and future economics of electricity storage. *Energy and Sustainability in Small Developing Economies*, *10*, 1176–1192. https://doi.org/10.1002/ghg.2030

Hirschhausen, C. v. (2017). Prosumage and the future regulation of utilities: An introduction. *EEEP*, *6*. 1–6. https://doi.org/10.5547/2160-5890.6.1.cvh

Howarth, R. W., & Jacobson, M. Z. (2021). How green is blue hydrogen? *Energy Science & Engineering*, *9*, 1676–1687. https://doi.org/10.1002/ese3.956

IEA. (2000). Experience curves for energy technology policy.

IEA. (2020a). Energy technology perspectives.

IEA. (2020b). Hydrogen projects database – Analysis – IEA. https://www.iea.org/reports/hydrogen-projects-database

IEC. (2019). Electrical energy storage: White paper.

IRENA. (2020). Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5C climate goal.

IRENA. (2019). Utility-scale batteries – Innovation landscape brief.

Jülch, V. (2016). Comparison of electricity storage options using levelized cost of storage (LCOS) method. *Applied Energy*, *183*, 1594–1606. https://doi.org/10.1016/j.apenergy.2016.08.165

Kakoulaki, G., Kougias, I., Taylor, N., Dolci, F., Moya, J., & Jäger-Waldau, A. (2021). Green hydrogen in Europe – A regional assessment: Substituting existing production with electrolysis powered by renewables. *Energy Conversion and Management*, *228*, 113649. https://doi.org/10.1016/j.enconman.2020.113649

Karaduman, Ö. (2020). Economics of grid-scale energy storage. Job Market Paper.

Kittner, N., Schmidt, O., Staffell, I., & Kammen, D. M. (2020). Grid-scale energy storage. In *Technological learning in the transition to a low-carbon energy system* (pp. 119–143). Elsevier.

Lund, H., Østergaard, P. A., Connolly, D., Ridjan, I., Mathiesen, B. V., Hvelplund, F., Thellufsen, J. Z., & Sorknæs, P. (2016). Energy storage and smart energy systems. *International Journal of Sustainable Energy Planning and Management*, *11*, 3–14. https://doi.org/10.5278/IJSEPM.2016.11.2

Lund, P. D., Lindgren, J., Mikkola, J., & Salpakari, J. (2015). Review of energy system flexibility measures to enable high levels of variable renewable electricity. *Renewable and Sustainable Energy Reviews*, *45*, 785–807. https://doi.org/10.1016/j.rser.2015.01.057

Madeddu, S., Ueckerdt, F., Pehl, M., Peterseim, J., Lord, M., Kumar, K. A., Krüger, C., & Luderer, G. (2020). The CO 2 reduction potential for the European industry via direct electrification of heat supply (power-to-heat). *Environmental Research Letters*, *15*, 124004. https://doi.org/10.1088/1748-9326/abbd02

McDonald, A., & Schrattenholzer, L. (2002). Learning curves and technology assessment. *International Journal of Technology Management*, *23*(7/8), 718–745.

McPherson, M., Johnson, N., & Strubegger, M. (2018). The role of electricity storage and hydrogen technologies in enabling global low-carbon energy transitions. *Applied Energy*, *216*, 649–661. https://doi.org/10.1016/j.apenergy.2018.02.110

Mehrjerdi, H. (2019). Optimal correlation of non-renewable and renewable generating systems for producing hydrogen and methane by power to gas process. *International Journal of Hydrogen Energy*, *44*, 9210–9219. https://doi.org/10.1016/j.ijhydene.2019.02.118

Mitchell, P., Waters, J., Esposito, D., & Michael, D. (2017). *Energy storage roadmap report*. Energy Systems Network.

Möst, D., Schreiber, S., Herbst, A., Jakob, M., Martino, A., & Poganietz, W.-R. (2021). *The future European energy system* (p. 321). Springer International Publishing.

Mostafa, M. H., Abdel Aleem, S. H., Ali, S. G., Ali, Z. M., & Abdelaziz, A. Y. (2020). Techno-economic assessment of energy storage systems using annualized life cycle cost of storage (LCCOS) and levelized cost of energy (LCOE) metrics. *Journal of Energy Storage*, *29*, 101345. https://doi.org/10.1016/j.est.2020.101345

Müller, T., & Möst, D. (2018). Demand response potential: Available when needed? *Energy Policy*, *115*, 181–198. https://doi.org/10.1016/j.enpol.2017.12.025

Munuera, L., & Alberto, T. (2020). Energy storage – Tracking clean energy progress: IEA tracking clean energy process. https://vipo.iea.org/tcep/energyintegration/energystorage/

Nykvist, B., & Nilsson, M. (2015). Rapidly falling costs of battery packs for electric vehicles. *Nature Climate Change*, *5*, 329–332. https://doi.org/10.1038/nclimate2564

Parra, D., Zhang, X., Bauer, C., & Patel, M. K. (2017). An integrated techno-economic and life cycle environmental assessment of power-to-gas systems. *Applied Energy*, *193*, 440–454. https://doi.org/10.1016/j.apenergy.2017.02.063

Pawel, I. (2014). The cost of storage – How to calculate the levelized cost of stored energy (LCOE) and applications to renewable energy generation. *Energy Procedia*, *46*, 68–77. https://doi.org/10.1016/j.egypro.2014.01.159

Platts. (2021). Air liquide completes 20 MW Canadian electrolysis plant. https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/012621-air-liquide-completes-20-mw-canadian-electrolysis-plant

Powell, W. B., George, A., Simão, H., Scott, W., Lamont, A., & Stewart, J. (2012). SMART: A stochastic multiscale model for the analysis of energy resources, technology, and policy. *INFORMS Journal on Computing*, *24*, 665–682. https://doi.org/10.1287/ijoc.1110.0470

Prol, J. L., & Schill, W.-P. (2020). The economics of variable renewables and electricity storage. *Annual Review of Resource Economics*, *13*, 443–467.

Rahman, M. M., Oni, A. O., Gemechu, E., & Kumar, A. (2020). Assessment of energy storage technologies: A review. *Energy Conversion and Management*, *223*, 113295. https://doi.org/10.1016/j.enconman.2020.113295

Schill, W.-P. (2014). Residual load, renewable surplus generation and storage requirements in Germany. *Energy Policy*, *73*, 65–79. https://doi.org/10.1016/j.enpol.2014.05.032

Schill, W.-P. (2020). Electricity storage and the renewable energy transition. *Joule*, *4*, 2059–2064. https://doi.org/10.1016/j.joule.2020.07.022

Schill, W.-P., Diekmann, J., & Zerrahn, A. (2015). Power storage: An important option for the German energy transition. *DIW Economic Bulletin*, *5*, 137–146UR.

Schill, W.-P., & Kemfert, C. (2011). Modeling strategic electricity storage: The case of pumped hydro storage in Germany. *The Energy Journal*, *32*. 59–88. https://doi.org/10.5547/ISSN0195-6574-EJ-Vol32-No3-3

Schill, W.-P., & Zerrahn, A. (2018). Long-run power storage requirements for high shares of renewables: Results and sensitivities. *Renewable and Sustainable Energy Reviews*, *83*, 156–171. https://doi.org/10.1016/j.rser.2017.05.205

Schill, W.-P., Zerrahn, A., Kemfert, C., & Von Hirschhausen, C. (2018). The energy turnaround will not fail because of electricity storage, Die Energiewende wird nicht an Stromspeichern scheitern. DIW Aktuell Nr. 11, DIW Berlin.

Schill, W.-P., Zerrahn, A., & Kunz, F. (2017). Prosumage of solar electricity: Pros, cons, and the system perspective. *Economics of Energy and Environmental Policy*, *6*, 7–31. https://doi.org/10.5547/2160-5890.6.1.wsch

Schmidt, O., Gambhir, A., Staffell, I., Hawkes, A., Nelson, J., & Few, S. (2017). Future cost and performance of water electrolysis: An expert elicitation study. *International Journal of Hydrogen Energy*, *42*, 30470–30492. https://doi.org/10.1016/j.ijhydene.2017.10.045

Schmidt, O., Melchior, S., Hawkes, A., & Staffell, I. (2019). Projecting the future levelized cost of electricity storage technologies. *Joule*, *3*, 81–100. https://doi.org/10.1016/j.joule.2018.12.008

Siddiqui, A. S., Sioshansi, R., & Conejo, A. J. (2019). Merchant storage investment in a restructured electricity industry. *The Energy Journal*, *40*. 129–164. https://doi.org/10.5547/01956574.40.4.asid

Sinn, H.-W. (2017). Buffering volatility: A study on the limits of Germany's energy revolution. *European Economic Review*, *99*, 130–150. https://doi.org/10.1016/j.euroecorev.2017.05.007

Sioshansi, R. (2010). Welfare impacts of electricity storage and the implications of ownership structure. *The Energy Journal*, *31*, 173–198.

Sioshansi, R. (2011). Increasing the value of wind with energy storage. *The Energy Journal*, *32*(2), 1–30.

Sioshansi, R. (2014). When energy storage reduces social welfare. *Energy Economics*, *41*, 106–116. https://doi.org/10.1016/j.eneco.2013.09.027

Sioshansi, R., Denholm, P., Jenkin, T., & Weiss, J. (2009). Estimating the value of electricity storage in PJM: Arbitrage and some welfare effects. *Energy Economics*, *31*, 269–277. https://doi.org/10.1016/j.eneco.2008.10.005

Staudt, P., Schmidt, M., Gärttner, J., & Weinhardt, C. (2018). A decentralized approach towards resolving transmission grid congestion in Germany using vehicle-to-grid technology. *Applied Energy*, *230*, 1435–1446. https://doi.org/10.1016/j.apenergy.2018.09.045

Steffen, B., & Weber, C. (2013). Efficient storage capacity in power systems with thermal and renewable generation. *Energy Economics*, *36*, 556–567. https://doi.org/10.1016/j.eneco.2012.11.007

Steffen, B., & Weber, C. (2016). Optimal operation of pumped-hydro storage plants with continuous time-varying power prices. *European Journal of Operational Research*, *252*, 308–321. https://doi.org/10.1016/j.ejor.2016.01.005

Sterner, M., & Stadler, I. (2019). *Handbook of energy storage* (p. 829). Springer.

Topalović, Z., Haas, R., Ajanović, A., & Hiesl, A. (2022). Economics of electric energy storage. The case of Western Balkans. *Energy*, *238*, 121669. https://doi.org/10.1016/j.energy.2021.121669

Tsiropoulos, I., Tarvydas, D., & Lebedeva, N. (2018). *Li-ion batteries for mobility and stationary storage applications: Scenarios for costs and market growth*. Publications Office.

Zablocki, A. (2019). Fact sheet. Energy storage.

Zach, K. A., & Auer, H. (2016). Contribution of bulk energy storage to integrating variable renewable energies in future European electricity systems. *WIREs Energy and Environment*, *5*, 451–469. https://doi.org/10.1002/wene.195

Zakeri, B., & Syri, S. (2015). Electrical energy storage systems: A comparative life cycle cost analysis. *Renewable and Sustainable Energy Reviews*, *42*, 569–596. https://doi.org/10.1016/j.rser.2014.10.011

Zerrahn, A., & Schill, W.-P. (2017). Long-run power storage requirements for high shares of renewables: Review and a new model. *Renewable and Sustainable Energy Reviews*, *79*, 1518–1534. https://doi.org/10.1016/j.rser.2016.11.098

Zerrahn, A., Schill, W.-P., & Kemfert, C. (2018). On the economics of electrical storage for variable renewable energy sources. *European Economic Review*, *108*, 259–279. https://doi.org/10.1016/j.euroecorev.2018.07.004

Zöphel, C., Most, D. (2017). The value of energy storages under uncertain CO2-prices and renewable shares, in: 2017 14th International Conference on the European Energy Market (EEM). 2017 14th International Conference on the European Energy Market (EEM), Dresden, Germany. IEEE, pp. 1-5, *5*, 37–44. https://doi.org/10.1007/s40518-018-0092-x

Zöphel, C., Schreiber, S., Müller, T., & Möst, D. (2018). Which flexibility options facilitate the integration of intermittent renewable energy sources in electricity systems? *Current Sustainable/Renewable Energy Reports*, *5*, 37–44. https://doi.org/10.1007/s40518-018-0092-x

Zweifel, P., Praktiknjo, A., & Erdmann, G. (2017). *Energy economics* (p. 333). Springer.

How to cite this article: Haas, R., Kemfert, C., Auer, H., Ajanovic, A., Sayer, M., & Hiesl, A. (2022). On the economics of storage for electricity: Current state and future market design prospects. *Wiley Interdisciplinary Reviews: Energy and Environment*, e431. https://doi.org/10.1002/wene.431