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Current and Future Costs of Storage for Electricity in a Decarbonized Electricity System

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ABSTRACT: As power systems globally are transitioning from fossil fuels to renewable sources, integrating energy storage becomes imperative to balance variable renewable electricity generation. The core objective of this paper is to conduct a comprehensive cost assessment of selected energy storage technologies from 2023 to 2050, focusing on the Austrian electricity market. Our method combines techno-economic assessment with the technological learning method to integrate various storage technologies into a renewable electricity system, using scenarios that account for decarbonization goals. Results indicate that pumped storage hydro exhibits none or negative learning effects, while lithium-ion batteries demonstrate significant investment cost decreases. Despite investment cost reductions, underground hydrogen storage continues to incur high total costs per kWh discharged due to low roundtrip efficiency, suggesting its future outlook depends on seasonal storage needs in fossil-free power systems. An important finding of this analysis underscores the importance of optimizing the ratio of electricity demand, renewable generation expansion and storage deployment for cost-effectiveness. Excessive storage deployment leads to lower utilization and higher costs, emphasizing the necessity of at least 1500 full-load hours for profitable operation across all storage systems. Strategic planning for optimal storage deployment is emphasized to optimize utilization and minimize costs.

Keywords: Storage costs; Technological learning; Pumped storage hydro; Battery storage; Underground hydrogen storage

1. Introduction

The ongoing global transition from fossil-based to renewable energy sources presents a significant challenge for power systems worldwide. Across the globe, countries are setting ambitious targets for renewable energy adoption, reflecting a widespread shift towards wind and solar energy in shaping the future of power landscapes. For instance, Europe has established initiatives like the "Clean Energy for All Europeans package", which underscores its commitment to renewable energy adoption [1]. This transition is already underway on a global scale, with renewable energy generation seeing substantial growth—from nearly zero in 1990 to 638 TWh in 2022 in Europe alone (Figure 1) [2]. The importance of energy storage in facilitating this transition is widely recognized, as energy storage systems provide the necessary flexibility and reliability for integrating intermittent renewable sources. Global entities, including the European Parliament, have emphasized the need for comprehensive approaches to energy storage to support the decarbonization of energy systems. In 2023, the European Commission issued recommendations on energy storage, highlighting its role in ensuring a secure and decarbonized energy future [3–5]. These recommendations underscore the critical need for long-term energy storage solutions to mitigate renewable generation curtailment and to provide services such as seasonal storage, security of supply and reliability. Energy storage also plays a vital role in stabilizing electricity prices by managing fluctuations and optimizing energy distribution from periods of surplus to deficits.

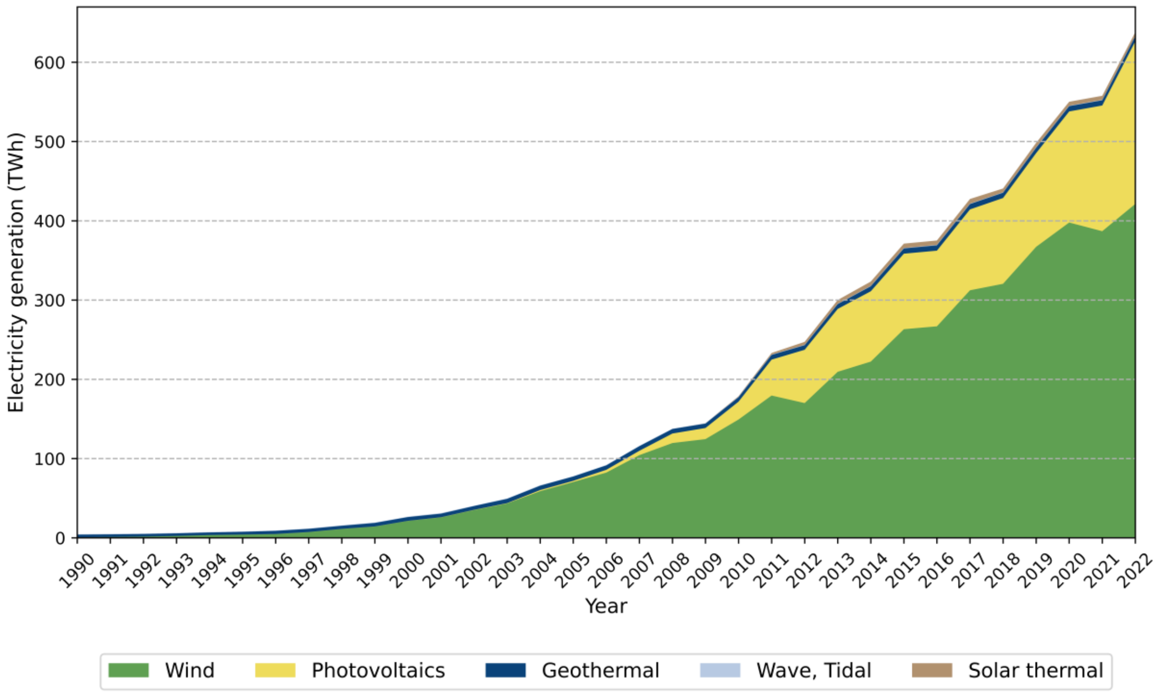

Figure 1. Evolution of variable renewable electricity generation in the European Union (1990–2022), illustrating the significant increase in renewable electricity generation within the European Union, growing from nearly zero in 1990 to 638 TWh in 2022 (own creation with data from [2,6]).

Austria's aim to achieve 100% renewable electricity in its energy system by 2030 underscores the increasing importance of energy storage on a national scale [7] (This goal, calculated on a net basis, entails exporting renewable electricity in equivalent measures to offset electricity generated from fossil fuels throughout the year). However, the future of storage development remains uncertain and will depend on various factors. Currently, pumped storage hydro is the dominant technology, but future cost trends, changes in the performance of other technologies, requirements for seasonal storage and geographical limitations of conventional pumped storage could reshape the landscape. Additionally, each technology has specific technical characteristics with resulting advantages and disadvantages, making it unlikely for a single technology to meet all flexibility requirements. Therefore, a combination of different storage technologies, as well as the utilization of other flexibility options such as demand-side management, grid expansion, or sector coupling, will be necessary to meet the demands of the transformed energy system.

In this context, understanding the trajectory of future investment costs of energy storage technologies is crucial. Hence, the core objective of this paper is to conduct a comprehensive assessment of the costs of selected energy storage technologies, both current and future, within the global context of the energy transition. This assessment is based on the scenario development of a considerable renewable electricity system with ambitious targets to decarbonize further and considers the technical specifics of the respective storage technologies. The aim is to provide insights into potential cost trends and their implications for the energy transition. This leads to the following research question: "*What are the actual and projected future total costs of jointly integrated storage technologies in a decarbonized power system?*".

The method applied involves a techno-economic assessment of the joint integration of selected storage technologies in a renewable electricity system. This assessment is grounded in modeling the Austrian electricity system under three scenarios that align with the decarbonization goals of the Austrian government, extending until 2050 to examine future costs. The rationale behind linking the analysis with our electricity system modeling based on Austria is that we already have calculations for different scenarios regarding future electricity prices and the future utilization of storage systems. Otherwise, we would have had to make estimates for these parameters. However, all other input factors are universally applicable, making the results and the model highly transferable to other countries pursuing electricity sector decarbonization goals. To evaluate the cost-effectiveness of storage under these scenarios, a comprehensive literature review of current storage costs forms the basis of our economic analysis, outlined in the Appendix A of this study. Additionally, our analysis utilizes a technological learning approach, which serves to calculate the future investment costs of the analyzed technologies and thus incorporates them as future costs into the evaluation. This holistic approach aims to provide valuable insights that can inform global strategies for the effective integration of energy storage in renewable energy systems.

Considerable research has been dedicated to exploring various storage technologies and their respective technical characteristics, such as Amirante et al. [8] and Rahman et al. [9]. However, the costs associated with these technologies remain a significant barrier to widespread integration. Consequently, a literature strain focuses on conducting economic analyses of selected storage technologies. These analyses can be categorized into cost analysis, profit analysis and system-value analysis, each serving distinct objectives [10]. In this paper, we concentrate on cost analysis, aligning with our research objectives. Specifically, we explore techno-economic analyses of different storage technologies and analyze future trends in storage cost development.

Primarily, such analyses rely on an approach that calculates the discounted costs per stored energy to assess the technology (the electricity from the storage must be sold at least at the cost per stored energy to make the storage investment economically viable) and to compare different technologies. In the literature, various terms are used for this purpose (levelized cost of electricity, levelized cost of stored energy (LCOS) and life cycle cost), which methodologically differ only in minor details. An interesting paper that chose this method (life cycle costs) to compare pumped storage hydro (PSH), compressed air energy storage (CAES), flywheel, electrochemical batteries, flow batteries, superconducting magnetic energy storage, supercapacitors and power-to-gas technologies is Zakeri and Syri [11]. The results show that the two examined mechanical energy storage systems are the most cost-effective options, particularly at the utility-scale (at the point of their investigation, 2015 published). However, for CAES, there is some uncertainty due to additional fuel and, thus, emission costs, which could not be accounted for over the entire lifetime of the facility.

A further analysis using the LCOS method by Jülch [12] arrives at similar conclusions regarding PSH, identifying it as the most economical solution for both short-term and long-term storage needs. At the time of the analysis (published in 2016), battery storage systems still incur high investment costs, although substantial cost reductions are anticipated. Through sensitivity analysis, it is demonstrated that the amount of energy discharged (storage utilization) and the electricity costs for charging have the greatest impact on the overall costs. Regarding PSH, Obi et al. [13] report varying costs per stored energy, depending on the reservoir size of the facility. Similarly, concerning battery storage, they conclude that these systems exhibit relatively higher costs for long-term storage and are thus particularly suited for short-term storage (frequency regulation). Vanadium redox flow (VRFB) batteries, according to Nikolaidis et al. [14], are particularly suitable for demand-shifting and reactive support, albeit still associated with high uncertainties. Mostafa et al. [15] also incorporate various power and energy ratings into their analysis and confirm that PSH offers the lowest costs for long-term storage. For medium-term storage, sodium-sulfur batteries are the most cost-effective, while for short-term storage, supercapacitors are preferred [15]. In a more recent paper by Mulder and Klein [16], storage costs are compared between a fixed electricity purchase price and a market-based variant simulated using an algorithm for strategic electricity procurement. PSH and thermal storage emerge as the most cost-effective options for durations of up to several days. Another significant finding is that, in the model, demand flexibility can reduce system-related electricity costs from 150 $/MWh to 100 $/MWh. Accounting for regional aspects in the analysis, Topalović et al. [17] find that, compared to battery storage, PSH offers the most economical solution in the Western Balkans. Across the studies reviewed, PSH consistently exhibits the lowest costs, which is unsurprising given its widespread adoption with considerable experience and technological maturity. However, forecasting the future competitiveness of alternative technologies remains less straightforward in the existing literature. Results vary considerably based on application contexts and regional factors, underscoring the importance of an application-specific analysis. This is exemplified in our case through power system modeling of Austria based on various decarbonization scenarios. Consequently, by considering the specific use case and existing policies, the total costs of new storage capacities can be calculated.

The expansion of analysis to include hybrid storage systems is explored by Moschos et al. [18], who combine lithium-ion batteries, superconducting magnetic energy storage and flywheel energy storage. Their findings reveal that the combination of lithium-ion batteries and superconducting magnetic energy storage yields the lowest storage costs at around 37 €/MWh. Härtel et al. [19] address concerns regarding curtailment through a scenario analysis focused on Germany's congested transmission grids. They introduce storage technologies to mitigate curtailment and observe that the necessity for storage is proportional to grid expansion; the less expanded the grid, the more essential storage becomes. Regarding current cost analyses, it is demonstrated that storing only the amounts of energy curtailed in the study year and in 2025 does not cover costs. Additional storage units that solely respond to surplus energy are not economically viable within the examined timeframe. Other studies focus their analyses on emerging technologies, such as Berrada [20] examining large-scale gravity energy storage and comparing it with conventional storage methods. Their findings suggest that gravity energy storage, with a cost of 202 $/MWh (based on calculations involving 1GW power and 125MWh energy for the system), presents a cost-effective alternative to conventional storage technologies. Similarly, Smallbone et al. [21] conduct a comparative analysis for pumped heat energy storage, indicating that the examined system, coupled with CAES, achieves cost competitiveness, potentially rivaling PSH. This comparative study underscores the profound influence of storage utilization rates on the overall economics of storage solutions.

Another strain of literature compares the costs of two storage technologies, as seen in Shahid et al. [22] and Escamilla et al. [23], particularly focusing on hydrogen and battery storage when operating as isolated systems. Both studies calculate that a combination of these technologies leads to the lowest costs. In Shahid et al. [22], these costs average 420 €/MWh across 21 French reference islands, while Escamilla et al. [23] report costs ranging from 860 to 1500 €/MWh, highlighting a 20% cost reduction achieved through hybridization in three European cities. A particular emphasis on underground hydrogen storage and resulting costs is found in Chen et al. [24]. Key storage types include depleted gas reservoirs, salt caverns and saline aquifers. Storage investment costs comprise four crucial components: cushion gas cost, geologic site preparation cost, compressor capital cost and well capital cost, with depleted gas reservoirs exhibiting the lowest overall costs. Recognizing the limitations of traditional cost-centric evaluations, Parzen et al. [10] introduce the "market potential method" as a complementary valuation approach. This method aims to identify storage options that are most valuable from an energy system perspective, which may not necessarily correlate with the lowest-cost storage type. For example, the properties of high-priced hydrogen storage may be more valuable than those of low-cost hydrogen storage. In summary, hybrid storage systems exhibit lower costs and purely cost-based analyses without considering the entire system may prove insufficient. Therefore, our analysis provides input data for calculations using a power system model that integrates different storage technologies and optimizes them from a system perspective, ensuring that the integrated storage types are utilized optimally. A general comparison of results regarding storage costs among studies is challenging due to varying assumptions, different analysis time frames (e.g., battery storage costs have changed significantly in recent years) and differing system designs, including system sizes. Additionally, it is often unclear whether both power and energy-related costs are included in the analysis for all technologies, which could also distort comparisons.

Based on current cost analyses, much will also depend on the future cost development when considering which storage technologies will prevail in the future energy system. Both market growth and innovation in storage technologies have the potential to drive down costs [25]. One approach to estimating future costs is through the experience curve or learning curves approach, which are often used interchangeably. However, unlike the learning curve, the experience curve should consider not only individual input costs like labor costs but also the total costs of the production process, incorporating all cost elements that may influence each other [26]. Consequently, the learning curve is confined to a single input factor and is considered a subset of experience curves [27] Thomassen et al. [28] argue that the distinction between the two becomes less clear, particularly when assembling different components into the final product. Therefore, we will use both terms interchangeably in this paper.

One of the primary works exploring the future cost trajectory based on experience curves is by Schmidt et al. [29], wherein the future investment costs of 11 electricity storage technologies are examined based on a capacity expansion of up to 1 TWh per technology. At this expansion rate, approximate average investment costs of 340 $/kWh (+/− 60) for stationary storage systems are projected, regardless of the technology. Through a bottom-up analysis, it is assessed that such capacity expansions with investments ranging from US$175–510 billion could be feasible and could be achieved around 2027–2040. In Schmidt et al. [30], these cost analyses are expanded from investment costs to future lifetime costs. It is calculated that from 2030 onwards, lithium-ion batteries are the most cost-effective, as long as they are utilized for short-term storage. The conclusion drawn from the analysis is that even with the cost reduction of lithium-ion batteries, alternative technologies may not be able to match their performance advantages, potentially rendering investments in alternatives futile. Kittner et al. [31] focus their analysis on storage technologies using technological learning for grid-scale energy storage. It is noted that due to the lack of public access to data and experiences regarding storage costs, there is some uncertainty, making it difficult to incorporate the rapid advancements in the development of different storage technologies into the analyses. It is also confirmed that from an economic standpoint, costs are the most critical indicators, underscoring the importance of publicly available cost data. Furthermore, one of the conclusions is that more data and studies across a variety of technologies and regions are needed to improve model accuracy and validation [31]. These analyses are comprehensively summarized and expanded upon in the book "Monetizing Energy Storage" [32]. Within the integrated assessment model MESSAGE, McPherson et al. [33] apply future cost development of storage. They conclude that the overall costs of the energy transition in the scenario with a pessimistic storage cost development are greater than if costs of storage and hydrogen technologies are further reduced through, for example, R&D investments.

Several studies specifically address the future cost development of one technology such as [34–37] for batteries and the following for power-to-gas technologies for storage. Baumann et al. [38] consider power-to-gas as one of the most promising technologies for long-term storage. Challenges include high capital costs and uncertainty about future cost and performance improvements. Therefore, in the paper by Schmidt et al. [39], an expert survey is conducted. It reveals that increased R&D funding could reduce capital costs by 0–24% and solely ramping up production could lead to cost reductions between 17–30%. Böhm et al. [40] present another learning cost analysis, indicating that investment costs for large power-to-gas plants could decrease by up to 75% in the long-term. Short- and medium-term advantages of proton exchange membrane (PEM) and solid oxide over alkaline electrolyzers have been found. In a more recent paper, Zeyen et al. [41] demonstrate that integrating the concept of technological learning into a sector-coupled model for Europe could reduce the overall system costs of electrolysis by 13% compared to scenarios without dynamic learning. They further illustrate that a faster expansion of electrolysis than in the RePowerEU plan could be cost-optimal. Ajanovic and Haas [42] offer a less optimistic view of future development compared to other studies, concluding that despite high technological learning potential, power-to-gas may struggle to compete in electricity markets.

While these studies provide valuable insights, they often lack a comprehensive view that integrates different storage technologies into a decarbonized energy system model, especially one tailored to specific regional decarbonization goals. This paper addresses this gap by providing a detailed cost analysis for integrating additional storage for electricity technologies into a highly decarbonized electricity system. This work focuses on three major technologies: PSH, battery storage and underground hydrogen storage. While the former two are already widely deployed, the imminent need for long-term storage in decarbonized energy systems suggests an upcoming role for hydrogen storage solutions. In the model employed in this work, hydrogen storage refers to the power-to-gas process involving electrolysis, followed by storage using underground facilities and subsequent re-electrification of hydrogen through CCGT for power generation.

This paper advances the current understanding in several key dimensions:

- Firstly, it provides an up-to-date and comprehensive analysis of current storage costs. By utilizing recent cost data, this study provides a more current assessment of storage technologies, reflecting the dynamic changes in the energy landscape, such as rising electricity prices and decreasing investment costs, especially for batteries. Due to additional stringent decarbonization goals, a reassessment based on recent cost data is important.
- Secondly, unlike previous studies that focus on single technologies or limited hybrid systems, this paper jointly integrates three main storage technologies (PSH, battery storage and underground hydrogen) into a power system with strong decarbonization targets. This approach considers short- to long-term storage applications and regional decarbonization targets. Parameters needed in the economic modeling, such as storage utilization (full-load hours) and electricity prices, were derived based on different decarbonization scenarios through a developed electricity system model, given real case inputs for those parameters and not just the author's assumptions. Within this model, specific applications of short- to long-term storage across various technologies were considered.
- Furthermore, for hydrogen storage, this study includes the entire process from production to re-electrification, offering a more detailed cost breakdown compared to studies focusing only on electrolyzers.
- Lastly, our work delves into the detailed calculation of future storage costs using the concept of technological learning, reflecting the expected cost changes of energy storage technologies. This perspective helps in understanding the potential economic impacts of scaling up storage technologies.

In conclusion, this paper not only reassesses current storage costs with up-to-date data but also integrates different storage technologies into a comprehensive, application-specific economic model. This approach reduces uncertainties and provides actionable insights for policymakers and investors in the context of a worldwide energy transition.

In this paper, in Section 2, the method is outlined. The results of the current and future economic assessment are provided in Section 3. Finally, Section 4 provides major conclusions of this work.

2. Materials and Methods

The method of this paper is a techno-economic analysis to evaluate the joint integration of key storage technologies within a decarbonized energy system. It entails the development of an economic model to assess the current and future total lifetime costs (overall cost of electricity coming from energy storage systems, including the energy purchase price) of new utility-scale storage systems across different transformation scenarios of the Austrian electricity system. The current investment costs of the storage systems and other costs are determined through an extensive literature review, while a technological learning approach is being employed to calculate future investment costs. Additionally, parameters such as storage utilization in the future energy system and electricity costs are derived from a self-developed representative model for the Austrian power system, reflecting scenarios for 2030 and 2050. This allows the respective total costs of storage (per kWh electricity output) to be calculated depending on the renewable expansion scenarios developed in the upstream model. The results of this modeling effort are currently in the publication process for a separate paper and are not part of the work within this paper. Consequently, this work focuses solely on the mentioned parameters, with a brief explanation provided in Section 2.3 regarding how these results were generated and how decarbonization scenarios were structured.

2.1. Techno-Economic Analysis of Actual and Future Total Costs of Storage

For the cost analysis, the initial step involves determining the total investment costs of each storage technology (IC_{sto}, in €/kW). This encompasses incorporating all components of investment costs, including energy storage system and installation costs, based on the methodology outlined by Viswanathan et al. [43], as depicted in Figure 2. These components comprise the specific investment costs of power equipment, controls, communication and grid integration (IC_p, in €/kW), the specific unit energy cost for the energy component of the energy storage system, incorporating supporting cost components (IC_e, in €/kWh), other specific costs (IC_o, in €/kWh), covering system integration, engineering, procurement and construction, project development and the discharge time (t, in hours). Using this calculation, the power-specific costs are converted into capacity-specific costs depending on the discharge time.

$$IC_{sto} = IC_p + (IC_e + IC_o)t \quad (\text{€/kW}) \tag{1}$$

<table>
<tr><th></th><th></th><th>Pumped storage hydro</th><th>Li-ion</th><th>Lead-acid</th><th>Redox Flow</th><th>Hydrogen</th></tr>
<tr><td rowspan="3">Storage system</td><td>Storage block</td><td rowspan="3">Reservoir construction and infrastructure</td><td>Li-ion modules in racks</td><td>Lead-acid modules in racks</td><td>Stacks and electrolyte tanks</td><td>Electrolyzer, underground storage, CCGT hydrogen turbine</td></tr>
<tr><td rowspan="2">Balance of system</td><td colspan="3">Container, cabling, switchgear and air conditioning</td><td rowspan="2">Blowers, humidifiers, mass flow controllers, and compressors</td></tr>
<tr><td colspan="2"></td><td>Pumps and piping</td></tr>
<tr><td rowspan="3">Energy storage system</td><td>Power equipment</td><td rowspan="3">Electromechanical powertrain – pumps/turbines, motors/generators and powerhouse construction and infrastructure</td><td colspan="3">Power conversion system and DC-DCconverter</td><td>Rectifier & Inverter</td></tr>
<tr><td>Controls and communication</td><td colspan="4">Controls/Energy management system</td></tr>
<tr><td>System integration</td><td colspan="3">System integration</td><td>Included in above costs</td></tr>
<tr><td rowspan="3">Installment costs</td><td>Engineering procurement and construction</td><td rowspan="3">Included in above ESS costs Contingency fees</td><td>Engineering procurement and construction</td><td>Engineering procurement and construction</td><td>Engineering procurement and construction</td><td>EPCEngineering procurement and construction</td></tr>
<tr><td>Project development</td><td colspan="4">Project development</td></tr>
<tr><td>Grid integration</td><td colspan="4">Grid integration</td></tr>
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Figure 2. Breakdown of investment cost components for energy storage technologies (adapted from [43]).

In addition to the investment costs, the annual fixed ($C_{O\&M_f}$, in $\frac{\text{€}}{\text{kW}}$/yr) and variable ($C_{O\&M_v}$, in €/kWh) operating, maintenance and repair costs, which include labor, parts and refurbishment-related costs, are also important for calculating the total lifetime costs of the storage system. Furthermore, end-of-life costs (IC_{end}, in €/kW), which are discounted to present value terms using a discount rate (r, in %) over the service life (n, in years), are considered.

$$IC_{end_{dis}} = \frac{IC_{end}}{(1+r)^n} \qquad (\text{€/kW}) \tag{2}$$

To annualize the investment costs the capital recovery factor (α) is calculated. This factor is determined using the service life and the discount rate applied.

$$\alpha = \frac{(1+r)^n \cdot r}{(1+r)^n - 1} \tag{3}$$

With all calculated parameters, including the respective full-load hours (FLH, in hours), the electricity costs (average energy purchase price at market rate) (C_{ele}, in €/kWh) and the round-trip efficiency of the storage system

(η_{sto}, in %), the total lifetime storage costs (C_{sto}, in €/kWh) per kWh from different storage systems can now be calculated.

$$C_{sto} = \frac{(IC_{sto} + IC_{end_{dis}}) \cdot \alpha + C_{O\&M_f}}{FLH\ \eta_{sto}} + \frac{C_{ele} + C_{O\&M_v}}{\eta_{sto}} \quad (\text{€/kWh}) \tag{4}$$

The future full-load hours and electricity costs are extrapolated from the model outcomes of previous scenario calculations (refer to Subsection 2.3). Based on the assumptions in the literature, the efficiency and service life of respective storage systems are determined. The real discount rate is held constant [44,45] and is assumed to be 5% following Blakers et al. [46]. All storage technologies are assessed using the same methodology without asserting specific risk profiles. The input data for the economic analysis are detailed in the following tables, along with their respective sources. Parameters are collected from both scientific literature and industry reports. Potential taxes or subsidies are not taken into account. Table 1 provides a summary of the various assumptions concerning technical parameters utilized in this paper. The ratio of power to energy capacity (E/P ratio) is chosen based on model parameters and assumptions.

Table 1. Summary of the technical parameters used in this research (2030/2050).

	Power Capacity (MW)	**Energy Capacity (MWh)**	**Round-Trip Efficiency (%)**	**Service Life (Years)**	**Source**
Pumped storage hydro–small	100	1000	79	60	[43,47]
Pumped storage hydro–large	1000	10,000	79	60	
Lithium-ion battery–small	1	2	90	16	[43,48]
Lithium-ion battery–large	10	20	90	16	
Lead-acid battery–small	1	2	85	10	[43,49]
Lead-acid battery–large	10	20	85	10	
Underground hydrogen storage–small	20	20,000	37/46	25	[48–50]
Underground hydrogen storage–large	500	500,000	37/46	25	

The underlying principle of the respective storage systems was that batteries serve as short-term, PSH as medium-term and hydrogen as long-term storage. Consequently, different E/P ratios were used and therefore, do not allow a direct cost comparison of the storage systems, but must be placed in relation to the respective area of operation. To show that the areas of operation of the technologies were chosen to be advantageous for the cost development in each case, the total investment costs for a uniform E/P ratio of 2 to 24 are shown in Figure 3 for comparison. Particularly important is the increase in total investment costs for both battery storage types with increased energy capacity, attributed to the higher influence of energy over power components. Hydrogen storage emerges as a long-term solution, with only minor changes in total investment costs relative to energy capacity expansion due to its minor energy component costs. The optimal use for long-term storage can be clearly seen here.

The costs of the investigated storage systems were selected from the literature as outlined in Table A1 in the Appendix A and are summarized in Table 2. All costs were converted to €2023 [51] and adjusted for inflation [52]. It must be noted that obtaining reliable data for investment costs from literature is challenging. Often, the specifics regarding the plant size to which the cost data relate, the components included (e.g., solely battery pack or entire system) and the origin year of these data are not clearly specified. Additionally, investment costs differ by region due to varying technical standards and conditions [53]. In this analysis, efforts were made to utilize cost data from Europe and North America, as they best reflect Austrian requirements.

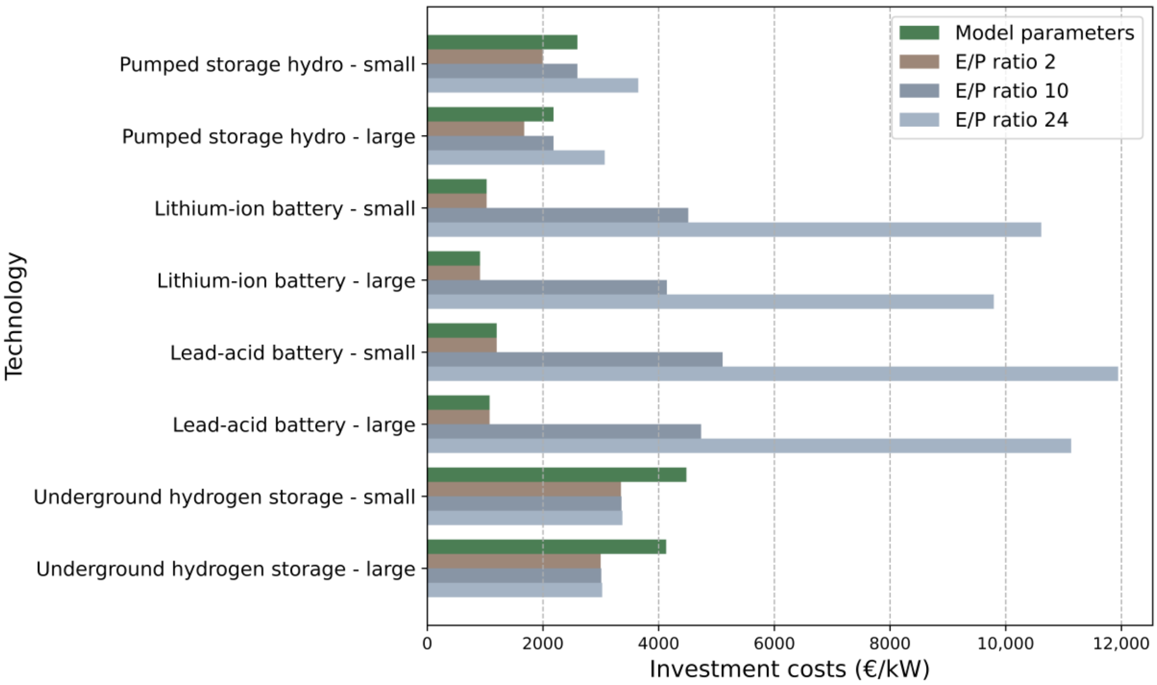


Figure 3. Total investment costs according to selected E/P ratio of the respective storage system (real value €2023).

Table 2. Summary of the economic parameters used in this research (real value €2023).

	Specific Investment Costs Power (€/kW)	Specific Investment Costs Energy (€/kWh)	Fixed O&M Costs (€/kW-yr)	Variable O&M Costs (€/MWh)	End of Life Cost (€/kW)	Source
Pumped storage hydro–small	1844	75	28	0.95	20	[43,49,54,55]
Pumped storage hydro–large	1549	63	15	0.95	20	
Lithium-ion battery–small	154	436	3.13	1.09	20	
Lithium-ion battery–large	104	404	2.56	1.09	20	
Lead-acid battery–small	223	488	3.91	1.00	20	
Lead-acid battery–large	164	457	2.87	1.00	20	
Underground hydrogen storage–small	3347	1	28.78	2.02	20	[43,48–50,53,56]
Underground hydrogen storage–large	2996	1	24.71	2.02	20	

2.2. Future Investment Cost Analysis—Technological Learning

The main methodology employed in the literature for calculating technological learning is the one-factor approach. This approach calculates future cost reductions as a function of cumulative production expressed by cumulative installed capacity and a constant learning rate over certain market phases throughout distinct market phases, a methodology also used in this paper. Mathematically, technological learning can be calculated using the cost function:

$$IC(x_t) = IC(x_{t_0}) \cdot (\frac{x_t}{x_{t_0}})^{-b} \quad (€/\text{kW}) \tag{5}$$

In this model, investment costs of one unit at time t ($IC(x_t)$, in €/kW)) decline as cumulative output at time t (x_t, in kW) rises. It is essential to have data on the investment cost of one unit at the time t_0 ($IC(x_{t_0})$, in €/kW) and the total output at the time t_0 (x_{t_0}, in kW). The cumulative output can be viewed as the installed capacity of a technology at time t, which can be represented by a diffusion curve. For instance, in the case of storage systems, we consider the overall global installed capacity. The exponent $-b$ in this formula characterizes the "learning effect" and is utilized in determining the learning rate (LR). The learning rate signifies a consistent percentage reduction in investment costs, with each doubling of cumulative installed capacity.

$$LR = 1 - 2^{-b} \tag{6}$$

For more detailed calculations, we can split the investment costs of the technology into conventional ($IC_{Con}(x_t)$, in €/kW) and new components ($IC_{New}(x_t)$, in €/kW) using the formula:

$$IC(x_t) = IC_{Con}(x_t) + IC_{New}(x_t) \qquad (\text{€/kW}) \tag{7}$$

The conventional "mature" components are typically associated with lower learning rates due to their larger "knowledge stock", thus not showing any observable learning effects. The new components reflect the innovative new technology components. This can further be broken down into national and international effects, where $IC_{New}\left(x_{Nat_t}\right)$ (in €/kW) denotes the specific national share and $IC_{New}(x_{Int_t})$ (in €/kW) the international share:

$$IC_{New}(x_t) = IC_{New}\left(x_{Nat_t}\right) + IC_{New}(x_{Int_t}) \qquad (\text{€/kW}) \tag{8}$$

The learning rates utilized in this paper, along with their respective sources, are presented in Table 3. Table 4 displays the future cumulative storage capacities considered in our model calculations. The data encompass a global geographic scope. For underground hydrogen storage the component-based approach, wich is being used for newer technologies is employed. The technology is divided into various components or subareas and the learning effects are then calculated based on the experiences of the component or another component related to it. Ultimately, the learning curve is the result of the sum of all analyzed components [57]. In this case each component—electrolyzers, re-electrification and underground storage reservoir— is examined due to significant discrepancies in the literature regarding the assumptions made about hydrogen storage. Some studies solely address the power-to-gas process (costs of electrolyzers), while others consider small above-ground storages within the framework of fuelling stations, etc., without re-electrification and still, others calculate re-electrification with fuel cells. Therefore, the components are calculated separately. For the other storage technologies, an average learning rate is assumed that includes all new parts of the technology. Regarding the scope of the learning rate, it is assumed that no or even negative further learning rates are factored in for PSH, given that it is already a fully mature technology, where additional learning effects are challenging to attain. Moreover, prices for PSH systems are anticipated to persistently increase, primarily due to the scarcity of sites with feasible costs and a lack of widespread acceptance. Conversely, it is anticipated that the prices of hydrogen storage and battery technologies will decrease due to learning effects, mass production, standardization and spillovers. This projection is supported by the International Energy Agency (IEA, 2020a), which anticipates high learning rates not only for batteries but also for other small, simple, modular and adaptable designs such as electrolyzers and fuel cells. However, recent increases in materials and labor costs, particularly in Europe due to high inflation, have led to rising costs of electrolyzers [53].

Table 3. Learning rates in % used in this research for new components of each storage technology.

	High	**Source**	**Low**	**Source**
Pumped storage hydro	0	[43]	−2	[31]
Li-ion batteries	18	[58]	16	[31]
Lead-acid batteries	10	[31]	4	[31]
PEM Electrolyzers	15	[59,60]	12	[61]
Hydrogen re-electrification	12	Own assumption	10	[43]
Underground storage reservoir	15	[62]	15	[62]

Table 4. Future cumulative storage capacities (The underground hydrogen storage is being investigated by each component separately, namely electrolyzers, re-electrification and underground storage reservoir).

	Unit	2023	2030	2040	2050	Source
Pumped storage hydro	GW	179	211	213	213	[63,64]
Battery storage	GW	58	126	388	945	
Lithium-ion batteries	GW	49	107	328	800	[64,65]
Lead-acid batteries	GW	1.0	2.5	7.7	18.8	
Electrolyzers—PEM	GW	0.9	56	558	982	[53,66,67]
Hydrogen electricity generation (by CCGT)	GW	0.03	4	52	100	[53], own assumption
Underground storage (Depleted gas reservoir)	TWh	0.24	5	18	30	[53]

This analysis faces some limitations, notably the inherent uncertainty in projecting future scenarios. Factors such as unforeseen technological advances, unexpected shifts in raw material prices and knowledge spillovers can significantly impact the rate of cost reduction, making short-term price forecasts unreliable [32]. Challenges in identifying future investment costs include difficulties in obtaining reliable data from the literature, as data is often outdated or lacks detail on storage system sizes. Besides the difference in cost assumptions depending on storage system sizes, investment costs may vary between countries; for example, labor-intensive technologies are highly influenced by labor costs in countries of production and installation. Furthermore, costs also differ depending on the location of construction, as observed in PSH [68]. Another determinant of PSH investment costs is that expanding existing power plants typically incurs lower investment costs compared to new developments, necessitating significant alterations to the water regime through the construction of additional reservoirs and conveyance systems [69]. Variations in storage types within a given technology, such as tank storage versus underground hydrogen storage, further contribute to cost disparities. Furthermore, different system boundaries are often drawn for cost analysis, such as in the case of battery storage, where sometimes only the battery packs are considered without factoring in the balance of system costs or installation costs. This disparity leads to varying cost estimates. For emerging storage technologies not yet available on the market, public cost data is nearly impossible to acquire. Additionally, cost estimations often depend on volatile market prices rather than stable costs, complicating accurate analyses. Despite these uncertainties, the methodology used provides a robust basis for estimating long-term costs, contingent on the assumptions made. Regarding the method used for technological learning calculations, with the one-factor approach, research and development expenditures are not considered. This could potentially overestimate the impact of production on cost reductions, particularly for early-stage technologies. Research expenditures have a relatively low elasticity regarding learning effects, indicating that production and research investments are not interchangeable [70]. This dual consideration complicates data collection but provides a more accurate picture. Adopting the component-based approach for all technologies could be a viable option. However, a comparison between the component-based approach and the one-factor learning rate approach by Böhm et al. [59] demonstrated that both methods are suitable.

2.3. Underlying Model and Scenario Description

To generate the input parameters for storage utilization through full-load hours and electricity prices, we utilize a cost-minimizing electricity market and energy storage dispatch model with three scenarios for the Austrian electricity system until 2050, published in [71]. This paper exclusively relies on existing model outcomes for further calculations within the economic model. While this chapter offers a brief explanation of the model and scenarios to facilitate the evaluation of the results and scenarios, the actual development of the model is not addressed in this work.

This model, developed to optimize the hourly allocation of generation and storage units, is aimed at minimizing short-term variable costs. It presents a simplified representation of the merit-order framework, suggesting an ideal competitive environment with the following objective function:

$$\min\left(\sum_{t\in T}\sum_{i\in I} c_i\ P_{i,t} + \sum_{t\in T}\sum_{sto\in STO} c_{sto}\ P_{sto,t}\right) \qquad (€/\text{yr}) \tag{9}$$

It operates at an hourly resolution for a typical year at a single node, enabling the model to consider short-term fluctuations and seasonal variations within the system. The equation consists of two parts: the initial section depicts the variable costs linked with dispatchable power plants (i) (i.e., fossil, waste, biomass and biomethane) across multiple time intervals (T), incorporating variable costs (c, in €/MWh). These costs, aside from covering operational and maintenance expenses, also encompass expenditures on fuel and carbon dioxide (CO_2), in addition to the capacity of the dispatchable power plants (P_i, in MW). The subsequent segment addresses the variable costs related to storage technologies (such as PSH, SH, battery and hydrogen storage) (sto) over the same time frame. The variable costs associated with storage (c_{sto}, in €/MWh) solely consider operational and maintenance costs, as the objective is to optimize the overall system. Consequently, the pursuit of profit maximization by individual storage operators is not a factor in this analysis.

To envision potential future scenarios until the year 2050, three distinct trajectories have been outlined to encompass a broad spectrum of possibilities regarding electricity demand and generation capacities, caused by policy goals, initiatives for electrification and endeavors to enhance efficiency. The core assumptions behind the three scenarios, named *policy* (A), *renewables and electrification* (B) and *efficiency* (C), are depicted in Figure 4. The *policy scenario* is based on specific climate protection measures implemented by the Austrian government, envisioning widespread electrification across various sectors. In the *renewables and electrification scenario*, a more ambitious expansion of renewable energy sources is assumed, alongside extensive electrification across multiple sectors, resulting in a corresponding increase in electricity demand. Conversely, in the third *efficiency* scenario, it is assumed that significant efficiency measures, particularly in space heating, are implemented, resulting in a lower overall increase in electricity consumption compared to the previous two scenarios. However, the scenario design is not part of this paper and is being further outlined in the mentioned paper [71]. What is most relevant in this publication is to show differences in cost calculation results depending on the underlying decarbonization goals and also designs of the future electricity system (e.g., on the amount of storage technologies deployed).

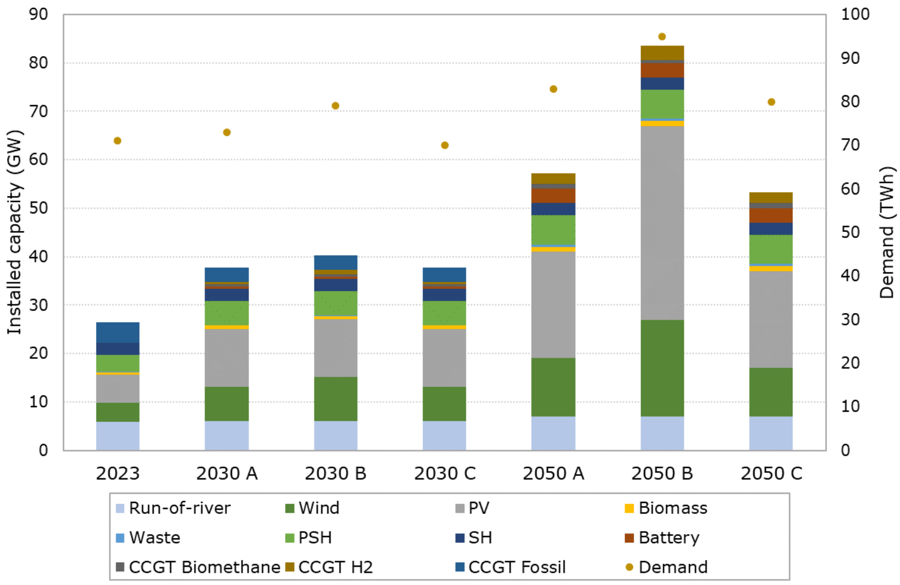


Figure 4. Installed capacities and electricity demand per scenario (*policy* (A), *renewables and electrification* (B) and *efficiency* (C)) and year.

The utilized storage technologies comprise short-term battery storage, medium-term PSH and reservoir storage hydro (SH) and seasonal hydrogen storage, as outlined in Table 5, with the respective scenario assumptions. It is assumed across all scenarios that there will be no fossil fuel-based generation in the energy system by the year 2050. This design ensures that supply and demand can be met consistently across various weather conditions.

Table 5. Overall installed capacities in MW according to scenario and years.

Scenario	*A Policy*		*B Renewables and Electrification*		*C Efficiency*	
	2030	2050	2030	2050	2030	2050
Pumped storage hydro	5000	6043	5000	6043	5000	6043
Batteries	534	3000	534	3000	534	3000
Electrolyzer	1000	5000	2000	7000	1000	5000
Re-electrification	440	2200	880	3080	440	2200

The underlying model is based on the Austrian electricity framework, which is distinguished by a substantial portion of renewable energy generation (mostly hydro) and the aspiration to attain complete renewable energy integration in the power sector on a national scale by 2030. It is noteworthy that the findings from our investigation carry significance not just for Austria but also for other nations navigating a comparable shift toward renewable energy sources.

The resulting full-load hours as model outcomes are presented in Table 6 and were calculated by dividing the energy discharged (E_{out}, in MWh) by each technology for each year through the installed capacity ($P_{sto_{\mathrm{m}}}$, in MW) of the respective technology:

$$FLH = E_{out} \,/\, P_{sto\_max} \qquad \text{(h/yr)} \tag{10}$$

Table 6. Full-load hours modeling results according to scenarios.

Scenario	*A Policy*		*B Renewables and Electrification*		*C Efficiency*	
	2030	2050	2030	2050	2030	2050
Pumped storage hydro	1606	1777	1165	2599	1687	1461
Lithium-ion batteries	577	417	401	646	576	379
Electrolyzer	3201	3210	2447	5120	3458	2685
Re-electrification	2704	1788	2067	690	2922	2265

The respective average electricity prices for 2030/2050 were derived for the *policy scenario* at 64/44 €/MWh, for the *renewables and electrification scenario* at 62/39 €/MWh and for the *efficiency scenario* at 60/46 €/MWh. These values serve as the input parameters for the economic model in this paper. The total costs of storage for the year 2023 are calculated using the average day-ahead spot market price for 2023 (102 €/MWh) [72], along with the data on full-load hours from Haas et al. [73].

The model has several limitations due to the extensive scenario analysis in the overall work, which are not fully outlined in this paper. One key constraint is the "copper plate" approach, modeling Austria as a single node and ignoring regional and network-specific limitations. Furthermore, flexibility restrictions in thermal generators are simplified by aggregating power plants and storage technologies into unified capacities within the electricity sector. Specifically, PSH is modeled as available storage capacity without detailing individual power plants and their reservoirs, which is a practical limitation. Due to the numerous scenario runs and data availability constraints, this level of aggregation was necessary. Exact load flows and exchanges with other countries are not modeled. Instead, total exchange capacities are treated as virtual import and export storage facilities to allow some balancing in the model. The assumption of a perfectly efficient market and perfect competition implies that the cheapest generators are always prioritized, with one market and trading horizon. Balancing markets are excluded and perfect foresight is assumed, eliminating forecast errors within a year. Despite considering three weather years to capture climatic variability, uncertainties in renewable generation are not fully addressed and climate change impacts are not included. These assumptions simplify modeling but may overestimate the flexibility potential in the electricity system.

3. Results

The future investment cost development of storage technologies is being calculated using the technological learning approach, employing the input data explained above under Section 2.2 and Equations (5)–(8). The data inputs for learning rate calculations can be found in Tables 3 and 4. This is carried out for scenarios with both low learning rates (Figure 5) and high learning rates (Figure 6). In both figures, investment costs are plotted against the cumulative installed capacity of the analyzed storage technologies, with the latter depicted on a logarithmic scale. This methodology provides an objective, evidence-based overview of potential future cost trends.

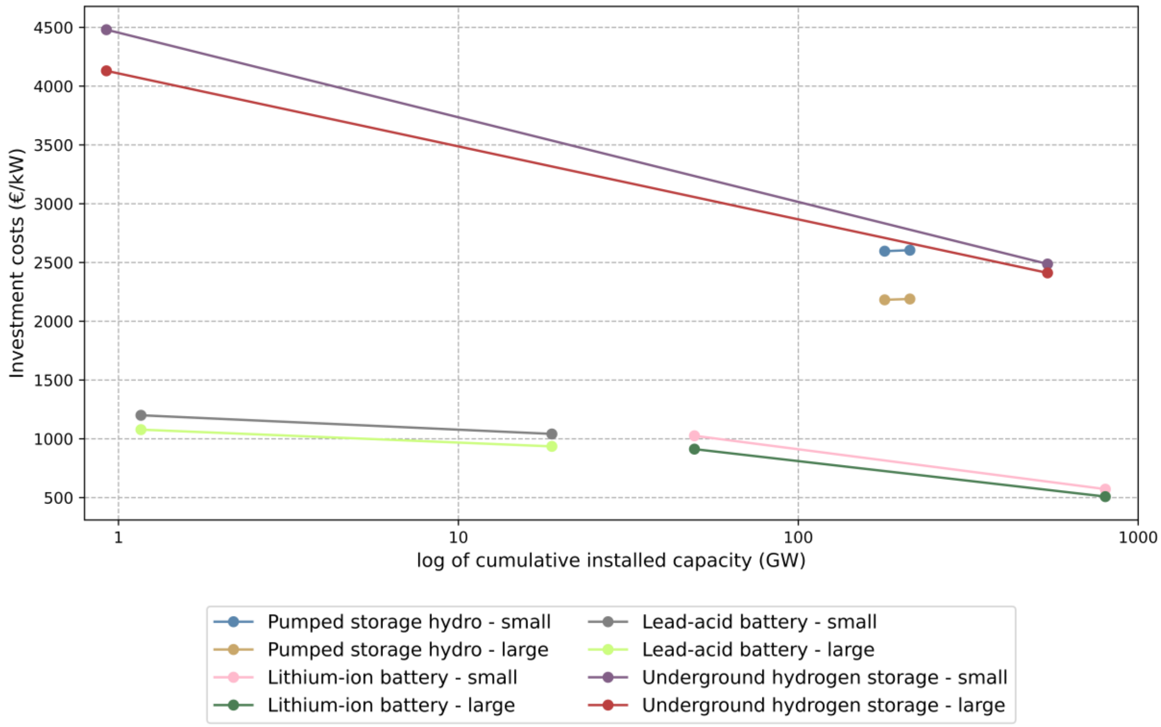


Figure 5. Investment cost reductions depending on the cumulative installed capacity of analyzed storage technologies calculated with low learning rates (corresponding learning rates and cumulative installed capacities as documented in Tables 3 and 4).

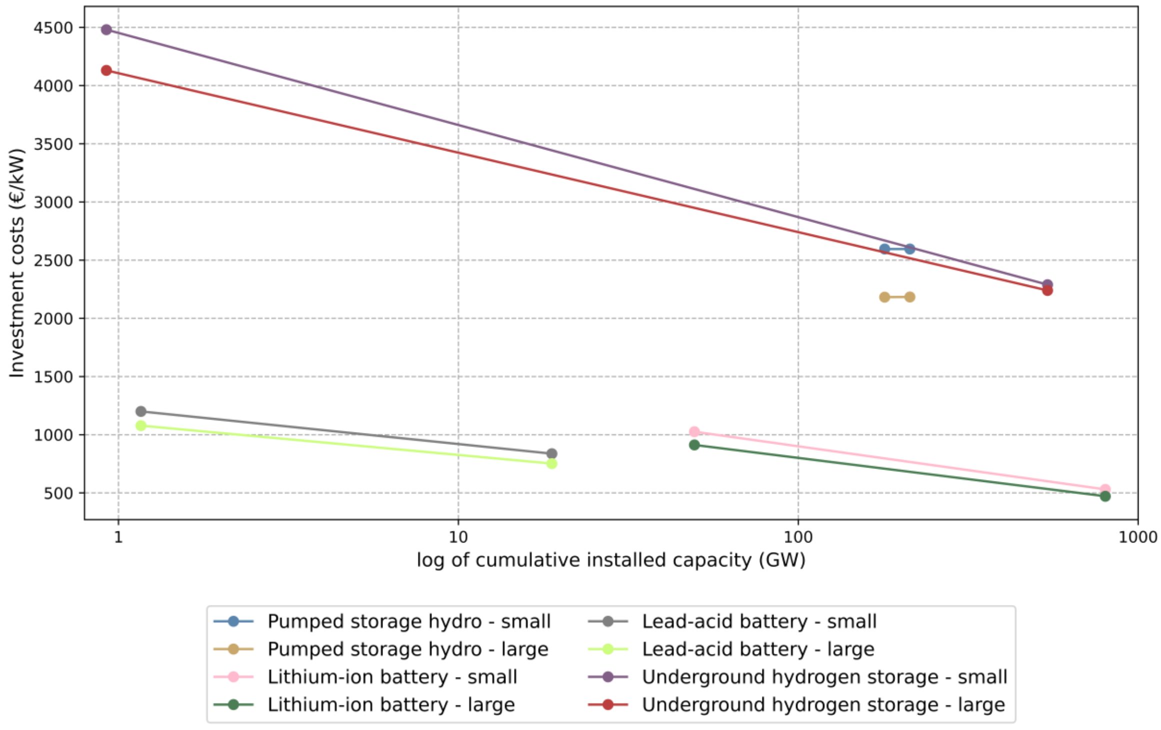
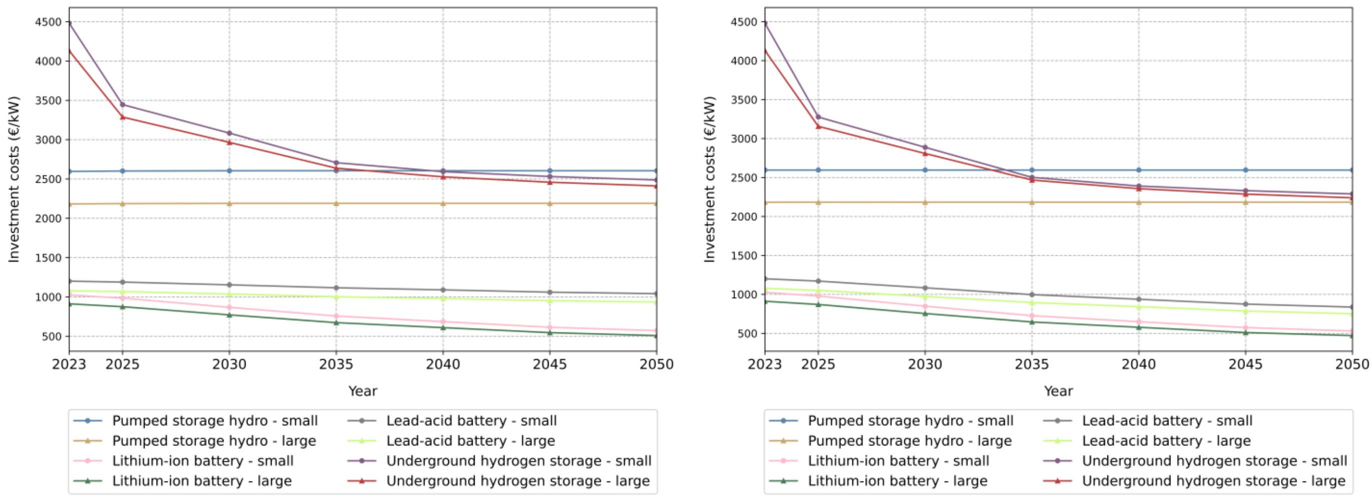


Figure 6. Investment cost reductions depending on the cumulative installed capacity of analyzed storage technologies calculated with high learning rates (corresponding learning rates and cumulative installed capacities as documented in Tables 3 and 4).

Cost reductions are observed across all technologies except for PSH. This is attributed to the absence of further or negative learning effects (0% low and −2% high) assumed for PSH, as it is considered a mature technology. Moreover, it is assumed that prices may rise due to the spatial constraints of conventional PSH, as many suitable locations have already been developed, leading to challenging social acceptance. Additionally, PSH is already the most deployed technology (179 GW worldwide in 2023) and doubling the installed capacities would be difficult to achieve. It is estimated that PSH capacities will reach approximately 213 GW by 2050. Hence, the results of PSH development are plausible. Regarding battery capacities, lead-acid batteries show lower cost reductions compared to lithium-ion batteries. This is mainly due to the expected lower expansion of installed capacities. Currently, approximately 1 GW of lead-acid batteries are available in 2023, which is expected to increase to about 19 GW by 2050. The learning rates of lead-acid technology are also reported to be lower in the literature (4% low and 10% high), resulting in lower learning effects compared to lithium-ion batteries. It is expected that lithium-ion will be the dominant battery technology in the future energy system, with corresponding capacity expansions expected (from 49 GW in 2023 to 800 GW in 2050), leading to an approximate halving of the investment costs of lithium-ion batteries with the respective learning rates. These rates are 16% in the low scenario and 18% in the high scenario.

The most substantial cost reductions occur in hydrogen storage, comprising of electrolyzers, underground storage and hydrogen turbines for re-electrification. Approximately 1 GW of PEM electrolyzers were already in use in 2023, but only 0.03 GW of CCGT turbines were for electricity conversion. However, existing natural gas turbine know-how can already be applied to the turbines, reducing the “new technology” part of it but resulting in lower overall costs. Consequently, the largest cost reductions are expected in electrolyzers, partly due to their relatively homogeneous nature and also because of the planned expansion (982 GW of PEM electrolyzers by 2050), which is significant. While these will not be exclusively used for hydrogen storage with electricity conversion, resulting cost effects will also reduce overall hydrogen storage costs. Calculations are performed using the three components and learning rates, namely electrolyzers (12% low and 15% high), underground storage (15% for both) and hydrogen turbines (10% low and 12% high). The learning rates per scenario and the assumed installed capacities, including sources, are summarized in Tables 3 and 4.

When examining the cost development of storage technologies in Figure 7 over the period from 2023 to 2050, the mentioned effects become even more apparent. The costs of PSH remain nearly unchanged or have increased. Due to significant cost reductions in underground hydrogen storage, cost parity between PSH and hydrogen storage is expected to be achieved from 2038 in the low scenario and from 2032 in the high scenario. By 2050, underground hydrogen storage costs in both scenarios are projected to be lower than those of small PSH and higher than those of large PSH. A substantial cost reduction of underground hydrogen storage is anticipated until 2030, attributed to increasing capacity expansions, followed by a slight flattening of this cost reduction curve. Overall, underground hydrogen storage costs are expected to decrease by 44% (small system) and 42% (large system) in the low scenario and by 49% (small system) and 46% (large system) in the high scenario between 2023 and 2050. Regarding battery storage, it is evident that lithium-ion batteries experience greater cost reductions, thus maintaining investment costs below those of lead-acid batteries over time. The cost gap between the two widens in the low scenario. Specifically, lead-acid battery costs are projected to decrease by 13% in the low and 30% in the high scenario and lithium-ion batteries by 44% in the low and 48% in the high scenario between 2023 and 2050. Lithium-ion batteries have demonstrated a remarkable price reduction in recent years, often linked in literature to that of crystalline silicon solar cells. The cost of battery cells has seen a remarkable 97% decrease since 1991 [74]. Consequently, it can be inferred that battery technologies (or at least the battery cells) are well suited for cost reductions through technological learning. It should be noted again that this is based on a defined E/P ratio through previous modeling. Altering these E/P ratios will change the investment costs or the relations between individual technologies, as demonstrated in Figure 3. For example, at an E/P ratio of 10, battery technologies are among the most expensive, while at a ratio of 2, they are among the cheapest when investment costs are regarded.



(**a**) (**b**)

Figure 7. Invstement cost reductions per year of selected technologies with low (**a**) and high (**b**) learning rates (corresponding learning rates and cumulative installed capacities as documented in Tables 3 and 4).

The calculated values of future investment costs are then further utilized in the subsequent analysis. However, it must be noted that extrapolating into the future is subject not only to the uncertainty of the derived rates but also to uncertainties associated with unforeseeable future changes. These may include technological breakthroughs, knowledge spillovers and shifts in raw material prices, all of which can fundamentally alter the rate of cost reduction [32]. Consequently, they cannot be used for short-term precise price forecasts. Nonetheless, this method provides a solid foundation for estimating future costs for long-term scenarios depending on the assumptions.

In a further step, the total costs of storage are now calculated according to the calculations described in Section 2.1 and Equations (1)–(4). The respective data input can be found in Tables 1 and 2. Starting from the year 2023, as shown in Figure 8, calculations for the years 2030 and 2050 are conducted for the *policy*, *renewables and electrification* and *efficiency* scenario. In 2023, there is a wide range of total costs among different technologies, ranging from 0.22 €/kWh (PSH large) to 0.8 €/kWh (underground hydrogen storage small). However, the influence of system size is also evident. Larger systems lead to lower total costs of storage for all storage technologies due to lower investment costs. The largest cost differences between small and large systems are observed in battery storage systems. Figure 8 provides a breakdown of capital, O&M and energy costs. In absolute terms, underground hydrogen storage shows the highest costs in all three areas in 2023. This is attributed to high investment costs and low roundtrip efficiency, resulting in higher electricity costs for storage In contrast, PSH exhibits the lowest costs, owing to its relatively high efficiency, low investment costs and long service life of equipment. Proportionally, energy costs represent the largest cost component for PSH in 2023 (52–58% of total costs). For all other examined technologies, it is the investment costs, accounting for 50–60% for lithium-ion batteries, 65–64% for lead-acid and 57–59% for underground hydrogen storage. For PSH, it is only 37–39%. Notably, electricity prices in 2023 remained relatively high, whereas earlier calculations before 2021 featured significantly lower electricity costs.

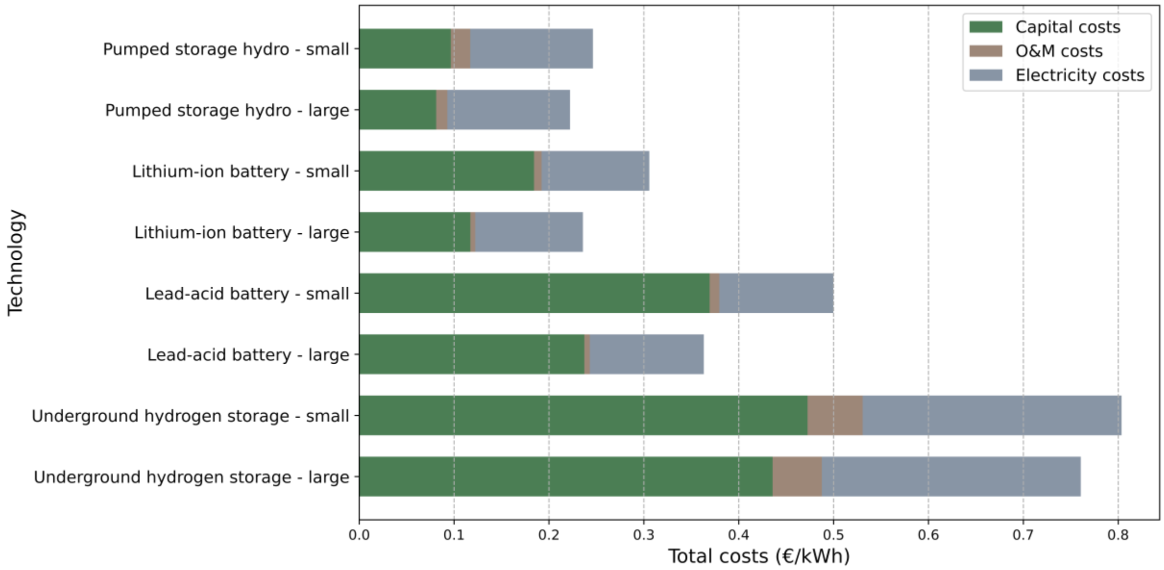


Figure 8. Total storage costs in €/kWh for each analyzed technology divided into capital, O&M and energy costs in 2023 (corresponding technical and economic parameters as documented in Tables 1 and 2).

Using the calculated future investment costs, the respective scenario assumptions (Table 5) and resulting full-load hours (Table 6), as well as electricity prices per scenario, the future total costs of storage for the year 2030 are computed in Figure 9 and for the year 2050 in Figure 10. These analyses are based on the investment cost development from the high learning rates scenario. In addition to the reduction in investment costs, an efficiency improvement in underground hydrogen storage has also been considered. Due to the reduction in investment costs and the lower electricity prices compared to the year 2023, a decrease in storage costs can already be observed. PSH large remains the most cost-effective technology in all scenarios, with costs ranging from 0.18–0.22 €/kWh in 2030 and 0.11–0.17 €/kWh in 2050. However, large lithium-ion batteries are also becoming increasingly economical, with a cost range of 0.2–0.25 €/kWh in 2030 and 0.12–0.17 €/kWh in 2050 due to investment cost reductions and high efficiencies of the technology. Underground hydrogen storage has been replaced by lead-acid batteries small, as the most expensive technology. In 2030, initially, only in the renewables and electrification scenario with 0.5 €/kWh, but in 2050, across all scenarios with a range of 0.25–0.41 €/kWh. Underground hydrogen small costs are between 0.38–0.46 €/kWh in 2030 and 0.24–0.27 €/kWh in 2050. Meanwhile, underground hydrogen storage has slightly lower costs, ranging from 0.37–0.45 €/kWh in 2030 to 0.23–0.27 €/kWh in 2050. For this cost reduction, the lower electricity price plays a role, but since the roundtrip efficiency in 2050 is still only 46%, not comparable to other storage technologies, the strong utilization of electrolyzers and storage in a fully decarbonized energy system largely contributes. Here, hydrogen storage becomes essential for shifting electricity from summer to winter.

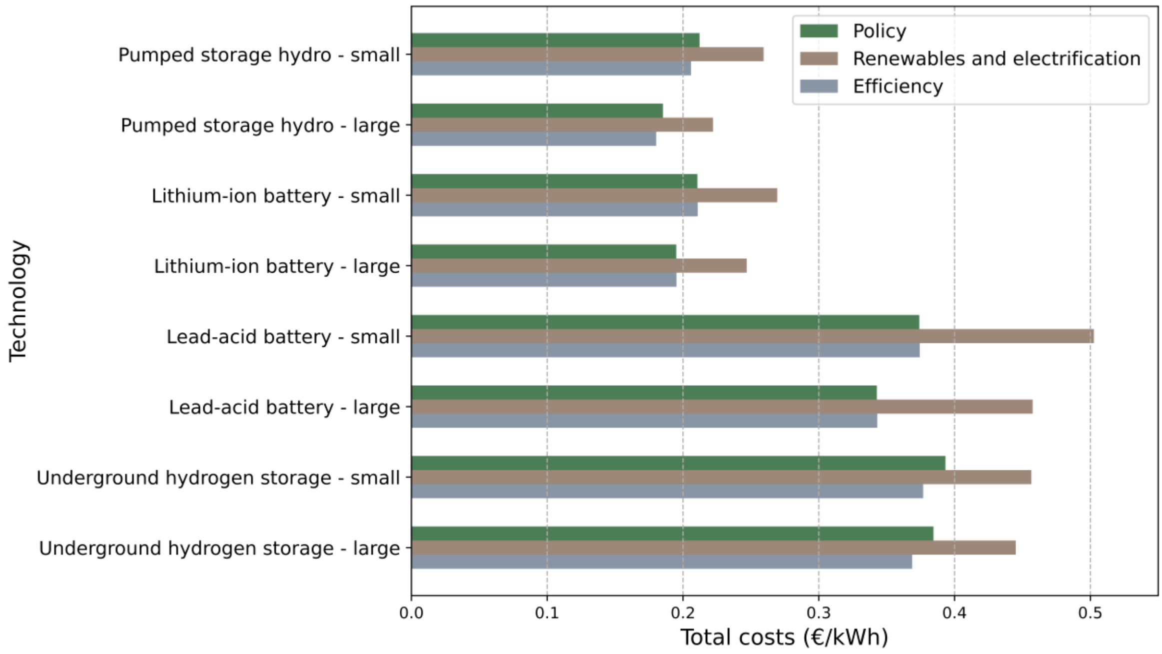


Figure 9. Comparison of total costs of storage per storage technology and scenario in the year 2030.

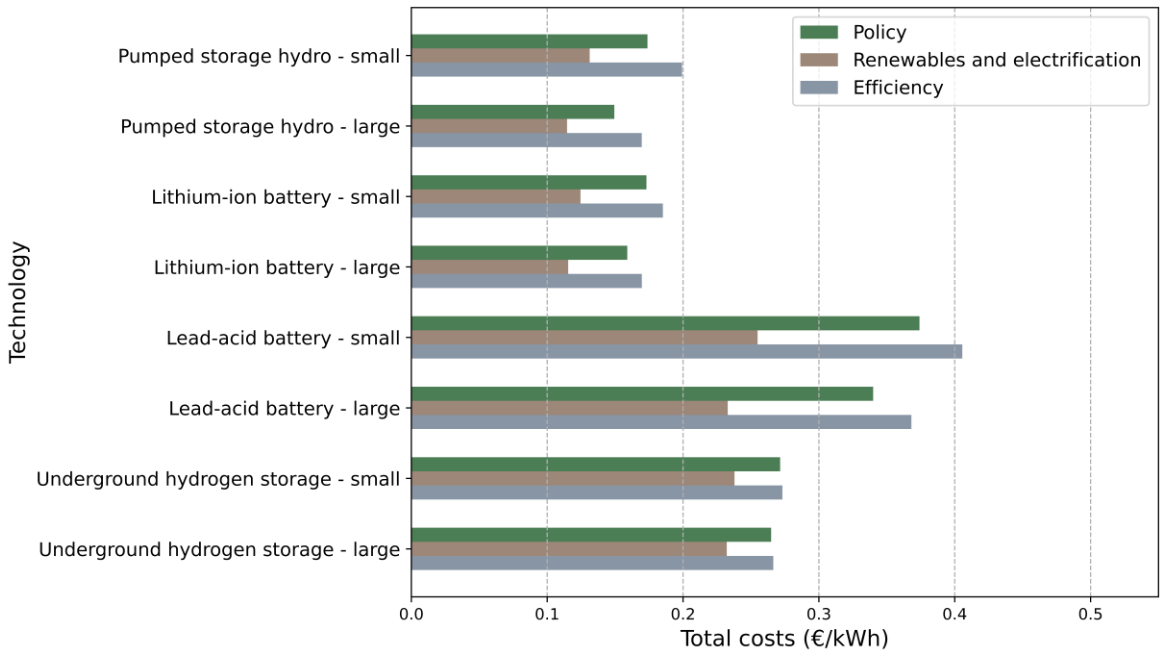


Figure 10. Comparison of total costs of storage per storage technology and scenario in the year 2050.

Analyzing not only technologies but also a scenario comparison is of interest. Overall, in 2030, the highest total costs of storage occur in the *renewables and electrification* scenario for all technologies. The reason for this is the higher deployment of underground storage technologies, leading to lower utilization of all storage technologies. However, this scenario assumes a higher overall electricity demand in the energy system and a higher expansion of renewable energy generation. With this background, a higher capacity of long-term storage is necessary to meet the electricity demand at all hours, resulting in higher storage costs. Conversely, the situation shifts in 2050, where the total storage costs in the *renewables and electrification* scenario are the lowest. Driven by a further increase in electricity demand (95 TWh) compared to alternative scenarios (80–83 TWh), coupled with the absence of fossil fuel generation, the planned storage capacities are utilized to a bigger extent. In the efficiency scenario, with lower consumption and lower variable renewable generation, the highest storage costs arise due to lower storage utilization. Therefore, optimal planning of storage capacities depending on their necessity in the energy system is important to maximize the utilization of existing storage and reduce overall costs. The detailed results of all scenarios and years are provided in Table 7.

Table 7. Total costs of storage for each analyzed technology per scenario and year in €/kWh.

Scenario	*A Policy*		*B Renewables and Electrification*		*C Efficiency*	
	2030	2050	2030	2050	2030	2050
Pumped storage hydro–small	0.21	0.17	0.26	0.13	0.21	0.20
Pumped storage hydro–large	0.19	0.15	0.22	0.11	0.18	0.17
Lithium-ion batteries–small	0.21	0.17	0.27	0.12	0.21	0.19
Lithium-ion batteries–large	0.20	0.16	0.25	0.12	0.20	0.17
Lead-acid batteries–small	0.37	0.37	0.50	0.25	0.37	0.41
Lead-acid batteries–large	0.34	0.34	0.46	0.23	0.34	0.37
Underground hydrogen storage–small	0.39	0.27	0.46	0.24	0.38	0.27
Underground hydrogen storage–large	0.38	0.26	0.45	0.23	0.37	0.27

A direct comparison between years is also of interest. When examining the *policy* scenario, it is evident that the costs decrease (except for small lead-acid batteries, where they remain the same) for all technologies, as depicted in Figure 11. The reduction in investment costs and declining electricity prices contribute to the reduced total costs per kWh for new storage technologies. It is important to note here that these costs were assumed for an exogenously determined expansion of storage capacity in the underlying storage model and the utilization of the storage (full-load hours) was determined based on these assumptions. However, if there were to be a higher expansion of storage capacities than assumed in the scenario development (see Table 5), this would reduce the full-load hours of the assumed capacities and lead to what is known as 'self-cannibalism'. That is to say, each new storage unit added would have fewer full-load hours than the previous one, thereby decreasing the price spread and, consequently, its own economic efficiency [75].

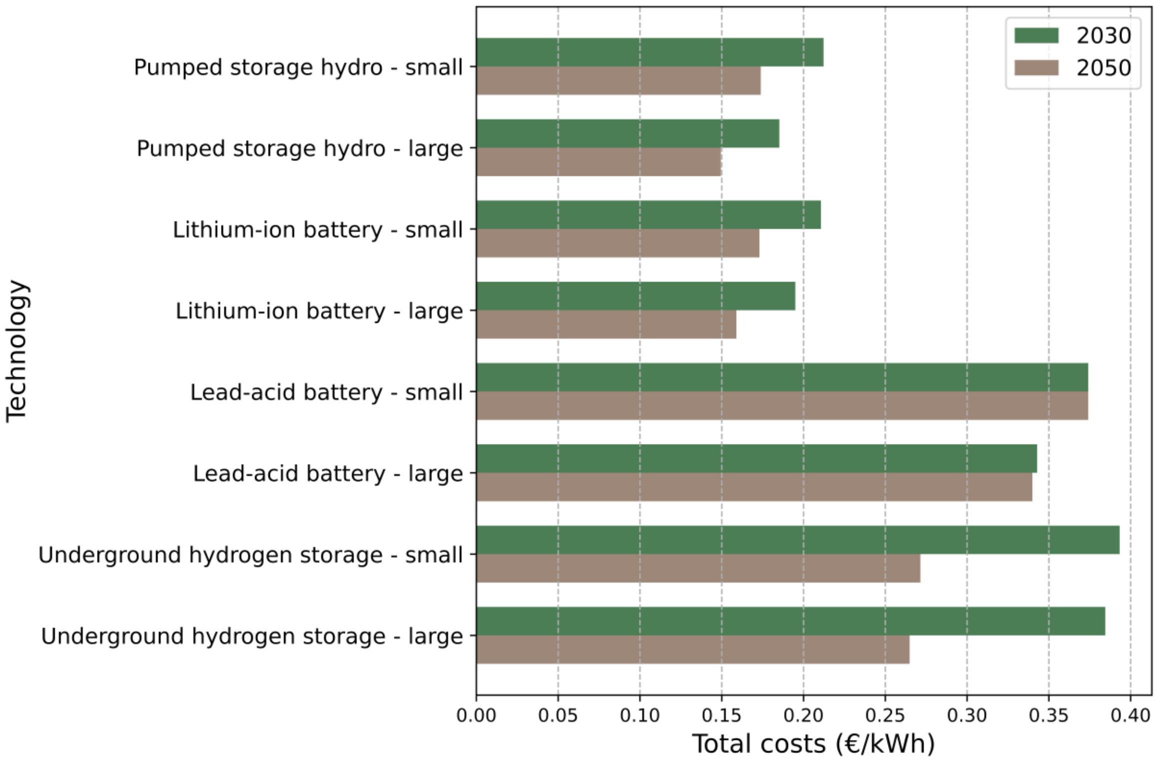


Figure 11. Comparison of total costs of storage across technologies from2030 to 2050 under the policy scenario.

This relationship between the full-load hours of storage and total costs is illustrated in Figure 12. When examining the overall storage costs of underground hydrogen storage, they are approximately five times higher at 500 full-load hours per year compared to 2500 full-load hours per year. Although not as strong, this influence is also noticeable with other technologies. This is crucial because full-load hours directly influence investment costs, which constitute the majority of total storage costs. The lower the annual utilization of the storage, the higher the total storage costs. Full-load hours in the range of 1500 appear to be necessary for the profitable operation of storage systems.

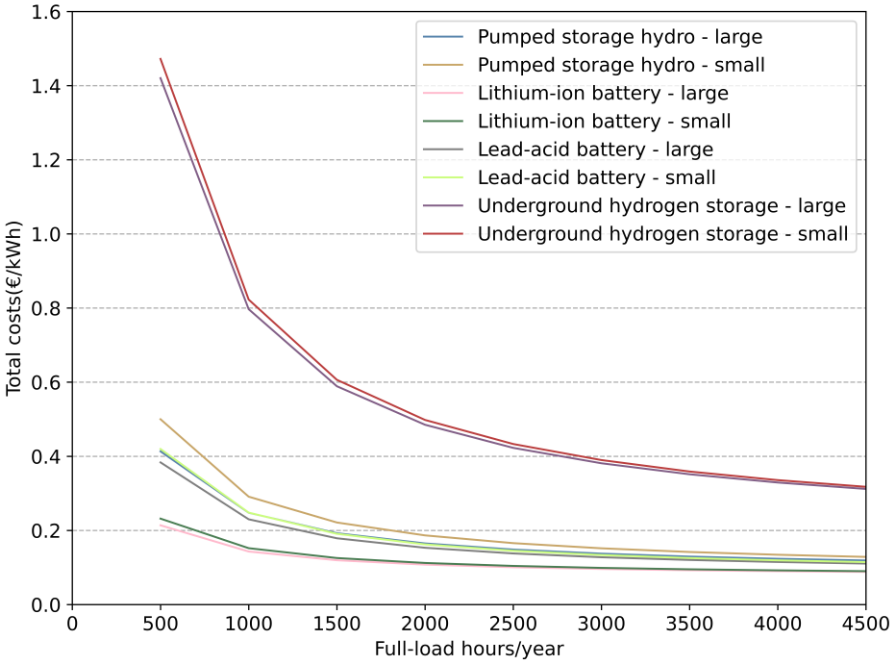
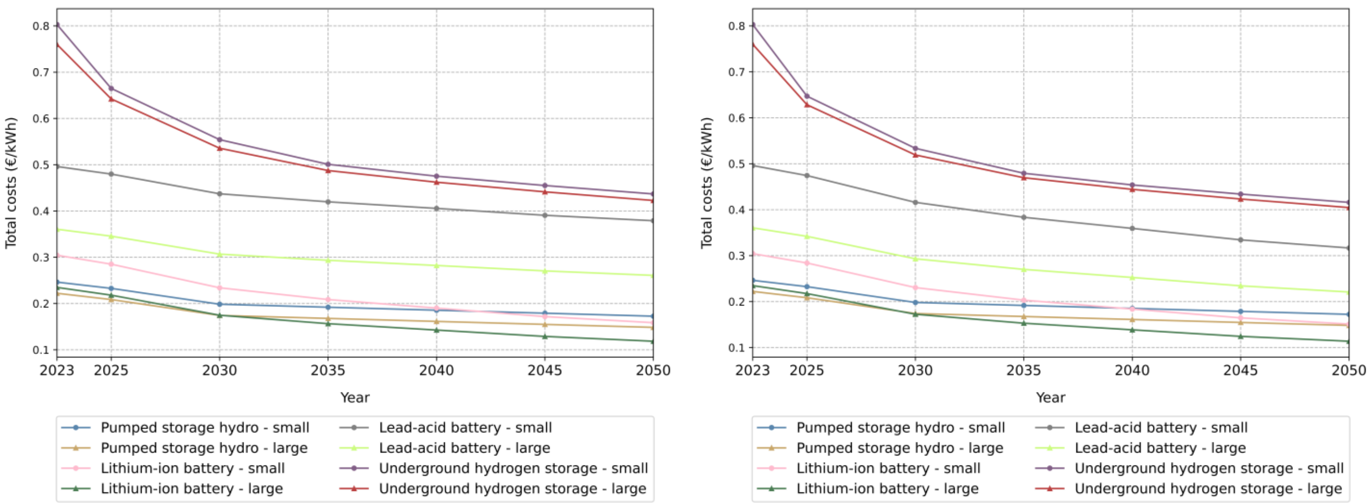


Figure 12. Total costs of storage in relation to the number of annual full-load hours for the policy scenario in the year 2030.

Figure 13 presents the trajectory of total costs of storage in the policy scenario throughout the year up to 2050 for both learning rate scenarios (low and high). The reductions in costs over the year, as previously demonstrated for investment costs, are once again evident here. The most cost-effective technologies are PHS and lithium-ion batteries. However, it must be noted that the latter are explicitly employed for short-term storage in the model.



(**a**) (**b**)

Figure 13. Prospects for the total cost of electricity storage with selected storage technologies until the year 2050 with low (**a**) and high (**b**) learning rates (corresponding learning rates and cumulative installed capacities as documented in Tables 3 and 4).

The findings of this study have significant implications for both policymakers and industry stakeholders aiming to optimize future investments in storage technologies. The projections of future investment costs, derived using the technological learning approach, provide an evidence-based foundation for understanding potential cost trends and making informed decisions. Policymakers should focus on supporting technologies with high learning rates and potential for significant cost reductions, such as lithium-ion batteries and underground hydrogen storage. Financial incentives, subsidies and research grants can accelerate the development and deployment of these and also other newer technologies. Implementing regulatory frameworks that encourage the adoption of storage technologies is crucial. Policies that facilitate grid integration, standardize safety protocols and streamline permitting processes will help reduce deployment barriers. Additionally, long-term energy planning must consider the projected cost reductions of various storage technologies, integrating storage solutions into national energy strategies to ensure a reliable and sustainable energy supply, particularly as renewable energy sources become more prevalent. For industry stakeholders, the projected cost reductions provide a basis for informed investment decisions. Prioritizing the development and deployment of technologies like lithium-ion batteries and underground hydrogen storage, which show substantial potential for cost reduction, is essential. Continuous investment in research and development can drive further cost reductions through innovations in storage technologies, improvements in efficiency and advancements in materials. Industry players must also adapt to evolving market conditions by aligning their business strategies with anticipated cost trends, exploring new business models, forming strategic partnerships and expanding into emerging markets where storage technologies can play a critical role. However, there are challenges and considerations that stakeholders must address. Obtaining reliable and up-to-date data on investment costs is challenging, as data gaps, outdated information and variations in system boundaries can affect the accuracy of cost projections. Efforts should be made to improve data transparency and availability. The cost reduction potential varies across technologies; mature technologies like PSH show minimal learning effects, whereas newer technologies like underground hydrogen storage have a higher potential for cost reductions. Stakeholders should consider the maturity level and scalability of technologies in their planning. Additionally, market prices for storage technologies can be volatile due to factors like raw material price fluctuations and short-term scarcities. This volatility poses a challenge for precise cost forecasting and necessitates adaptive strategies to manage market risks. In conclusion, the analysis underscores the importance of strategic planning and informed decision-making for both policymakers and industry stakeholders. By understanding and leveraging the projected cost trends of storage technologies, stakeholders can optimize their investments, foster innovation and contribute to the development of a sustainable and reliable energy system. The findings highlight the need for continuous support and adaptation to technological advancements and market dynamics, ensuring that storage technologies play a pivotal role in the future energy landscape.

4. Conclusions and Outlook

This paper provides a detailed analysis of storage costs using a techno-economic approach and the method of technological learning, both for the current period and for a future decarbonized energy system in Austria. Through an extensive literature review on storage investment costs, all cost components of the entire storage system were incorporated into the analysis. The assessment of future investment cost trends for storage technologies offers a comprehensive insight into potential developments.

Among all the various storage technologies analyzed, cost reductions are observed except for PSH, which, as a mature technology, shows minimal or negative learning effects, resulting in stagnant or increased costs. Conversely, lithium-ion batteries demonstrate significant cost reductions, becoming the dominant technology for short-term storage due to expected capacity expansions and high learning rates. Hydrogen storage, encompassing electrolyzers, underground storage and hydrogen turbines, shows the most substantial investment cost reductions. Electrolyzers, in particular, benefit from significant expansion plans and a relatively homogeneous nature. Despite initial higher costs, underground hydrogen storage is projected to achieve investment cost parity with PSH by the 2030s. Nevertheless, it is still experiencing higher energy losses during the whole storage process, thus experiencing higher total costs of storage per kWh discharged. The future use of underground hydrogen storage will depend significantly on the need for seasonal storage, as it may not be competitive with other storage technologies based solely on cost considerations. Nonetheless, in scenarios prioritizing fossil-free power systems, hydrogen storage could emerge as a critical option for providing electricity during periods of insufficient renewable generation, provided no other seasonal storage technology becomes competitive by then.

In summary, the technological learning approach suggests that for future reductions in investment costs of storage technologies, several key factors must be considered:

- Technologies should remain homogeneous over the technology's lifespan (without changes or adaptations in functionality), which is rarely achievable in practice.
- Modularity and homogeneity are crucial factors for significant cost reductions, as evidenced by lithium-ion batteries. Complex designs typically achieve lower cost reductions (for example, underground hydrogen storage consists of different components that must interact and whether individual components like electrolyzers will achieve significant cost reductions remains to be seen).
- The technology should not be so widely deployed that there is no potential for capacity doubling, as is the case with PSH. Due to topographical constraints, additional expansion is limited, resulting in a decrease in the driving

force for technological learning. Additionally, doubling the stock becomes more challenging and time-consuming as deployed quantities increase.

Identifying future investment costs presents several challenges:

- Obtaining reliable data from literature is generally difficult. Data is often either outdated or lacks information on plant sizes and system boundaries of the analysis (whether the entire system is considered or possibly only the battery pack).
- For the analysis of new types of storage not yet available in the market, obtaining public cost data is nearly impossible.
- Estimations typically rely on market prices rather than costs and market prices may temporarily rise or be volatile due to short-term scarcities. This also poses challenges in conducting accurate cost analyses.

However, from an economic standpoint, costs remain one of the key indicators, making transparent public access to cost data, including the listing of different components, crucial.

The paper confirmed the specific applications of the integrated storage technologies in the modeling. Battery storage is best suited for short-term storage and cannot compete with long-term storage technologies due to high energy-related costs. PSH is clearly intended for medium to long-term storage but remains competitive for short-term storage in the medium run. Underground hydrogen storage is distinctly suitable for long-term storage use. The energy-related costs are extremely low, meaning that especially in depleted gas reservoirs, a significant amount of hydrogen can be stored at minimal cost. The high total costs lie in the conversion technology, re-electrification and the high energy losses due to the low conversion efficiency.

The calculations demonstrate that, in addition to investment cost development and the previously mentioned roundtrip efficiency of each technology, the cost of electricity used for charging and the number of full-load hours strongly influence storage costs. Key points include:

- Different scenarios have shown that an optimal ratio of electricity demand, renewable generation expansion and storage deployment leads to the most cost-effective results. Excessive storage deployment, compared to renewable generation, results in lower storage utilization and overall higher costs. This could be seen with all technologies and can be referred to as ‘self-cannibalism’ of storage [75].
- The influence of full-load hours is most significant for underground hydrogen storage, where total costs of storage vary by a factor of five between 500 and 2500 full-load hours per year.
- Full-load hours in the range of 1500 are necessary for the profitable operation of all storage systems.
- With the complete decarbonization of the electricity grid, electricity costs decline over time due to the diminishing reliance on expensive fossil fuels. This was demonstrated in the modeling, leading to a reduction in costs from 2030 to 2050 in all scenarios. However, optimal storage deployment remains pivotal to realizing these benefits.

This underscores the significance of strategic planning, which is essential for optimizing utilization and minimizing overall costs. It’s essential to also consider other flexibility measures, such as demand-side options, demand response, sector coupling, or grid expansion, as these factors compete with each other to some extent. However, the applied cost calculation method can only assess electricity-to-electricity storage options. Therefore, it is advisable to extend the analysis to include additional flexibility options in future studies.

Given the ongoing dynamic and often unpredictable developments in the energy market, as well as the general uncertainties associated with long-term forecasts, it is further recommended to continuously update cost calculations. The one-factor approach used in this paper for future cost calculation could be expanded to a two-factor model. In two-factor models, not only the cumulative production/installed capacity is considered, but also research and development expenditures, which can also contribute to cost reduction [76]. Neglecting the influence of research and development can lead to an overestimation of the production influence in one-factor approaches, especially for technologies in early market phases. Consequently, there is a relatively low elasticity regarding the learning effects of research expenditures and capacity expansion, leading to the conclusion that research expenditures cannot be substituted by production and vice versa [70]. However, this increases the problem of already challenging data collection for cumulative production with regard to research expenditures, leading to further significant uncertainties. Extending the component-based approach to all technologies would also be another possibility, although a comparison of the results of the component-based approach with the one-factor learning rate approach by Böhm et al. [59] found both approaches to be appropriate.

Furthermore, it is recommended to include additional storage technologies in future works, such as pumped heat energy storage for long-duration storage or gravity energy storage, as mentioned in the literature. This approach allows for adaptation to unforeseen technological breakthroughs or shifts, potentially favoring emerging, more efficient technologies. Another potential method extension could involve integrating a metric for the manufacturing emissions of each technology, allowing for an assessment not only based on technical and economic criteria but also on environmental considerations. The availability of raw materials, especially for battery technologies, is expected to play a significant role in future developments, with cobalt-free batteries already being developed due to extraction conditions and cost considerations [77,78]. Therefore, incorporating indicators reflecting these aspects and raw material availability could additionally provide valuable insights into future trends.

Appendix A

Table A1. Literature review on investment costs of energy storage systems (Sources are displayed in alphabetical order).

	Power Component (€/kW)		**Energy Component (€/kWh)**		**Source and Remarks**
	Min	Max	Min	Max	
Pumped storage hydro	1190	5950			[79]
	577	4135	5	96	[80] (100 MW–5000 MW)
	400	2200	40	470	[49] (10 MW–3 GW)
	456	1710	46	171	[81] (10 MW–3 GW)
	1473	2209			[73] (200 MW–350 MW)
	362	905	1.8	45	[82] (30 MW–10 GW; seasonal storage)
	1100		27		[48] (200 MW, 1200 MWh)
	1309		12		[54]
	995		45		[32,55]
	1549	1844	63	75	[43] (100 MW–1 GW, 10 h)
Lithium-ion batteries	238	833			[79]
	577	3846	577	3654	[80] (up to 100 MW)
	600	3500	350	1200	[49] (<500 MW)
	171	1140	798	1482	[81] (1 kW–50 MW)
	1227	2945			[73] (2.5 kW–0.5 MW)
	226		136	181	[82] (0.001 MW–1000 MW)
	286		505		[48] (1 MW, 1 MWh)
	42		223		[54]
	226		271		[32,55]
			678		[83]
	104	154	363	436	[43] (1 MW–10 MW, 2 h–10 h)
Lead acid batteries	119	298			[79]
	288	577	192	385	[80] (up to 40 MW)
	250	2000	300	1000	[49] (<40 MW)
	114	570	114	228	[81] (some MW)
	271		290		[32,55]
	164	223	412	488	[43] (1 MW–10 MW, 2 h–10 h)
Hydrogen storage	2280	5700	1	11	[81] (1kW–1 GW)
	2000	5000	5	13	[49] (1 kW–1 GW electrolyzer and fuel cell)
	1283		0.48		[48] (geologic storage, PEM electrolyzer, CCGT)
	2985		1		[56] (geologic storage, PEM electrolyzer, CCGT)
	5069		1		[56] (geologic storage, PEM electrolyzer, fuel cell)
	1190		0.24		[54] (power-to-gas only)
	4525		27		[32,55]
	2861		6		[43] (100 MW–1 GW, 10 h–24 h)
PEM electrolyzer	2633				[40] (5 MW)
	1666	2499			[84]
	1638	2574			[73] (0.5 MW–10 MW)
	1538	1810			[53]
	2691				[85]
	688	1376			[60] (minimum 10 MW)
	80				[48] (20 MW)

		1703					[56]
	3193		2737				[86] (500 kW–5 MW)
	1452		1755				[87] (1 MW–20 MW)
		590					[50]
		1301					[43]
Energy storage hydrogen					38		[88] (depleted gas reservoir, including cushion gas, compressor andwell)
					7		[89]
					0.48		[48] (20,000 MWh)
					8		[56] (aboveground, pressurized tank)
					1		[56] (geologic)
				14		17	[90] (very small system)
					6		[43]
Gas turbine hydrogen		1269					[56] (including NOx control)
		595					[50]
CCGT hydrogen		1203					[48] (20 MW)
		1282					[56] (including NOx control)
		897					[50]
PEM fuel cell		3366					[56]
		1305					[43]
		1089					[50]
Solid oxide fuel cells		1770					[50]

Author Contributions

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