

Battery storage is a lever of the energy transition – grid-scale storage smooths electricity prices

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Since 1991, the prices of lithium-ion cells have fallen by 99%. The reasons for this are economies of scale and efficiency gains along the entire value chain. The sharp rise in demand for electric cars in particular has favoured this scaling.

In Germany, installed battery storage power has more than octupled within five years. Residential storage systems account for the largest share. Among grid-connected grid-scale storage, lithium-ion technology is continuously gaining market share, while other forms of energy storage are stagnating or are not yet ready for the market.

In California, battery storage systems demonstrably contribute to lowering wholesale electricity prices. By charging at times of low and discharging at times of high electricity prices, they have a price-dampening effect.

Our analysis of the European electricity market shows that electricity price zones with a high density of grid-scale battery storage exhibit a narrower spread in wholesale electricity prices. For residential and commercial storage, by contrast, the relationship is negligible.

In Germany, the grid-supportive expansion and operation of battery storage is being held back by complex grid connection procedures and by a market design with a single, uniform wholesale electricity price. As a result, local grid congestion is barely taken into account. Dynamic grid fees offer one approach to pricing in this grid congestion.

With a share of 45% of the electricity consumed in Germany, wind and solar energy formed the backbone of the German electricity mix in 2025.¹ This lowers wholesale electricity prices overall, but also makes them fluctuate more strongly, because feed-in from wind and sun depends on the weather.² The number of hours with negative wholesale electricity prices³ is rising accordingly, and prices in these hours are on average falling ever deeper.⁴ This phenomenon can be observed worldwide in many countries in which grid investment and flexibility mechanisms are not keeping pace with the expansion of wind and solar energy.⁵

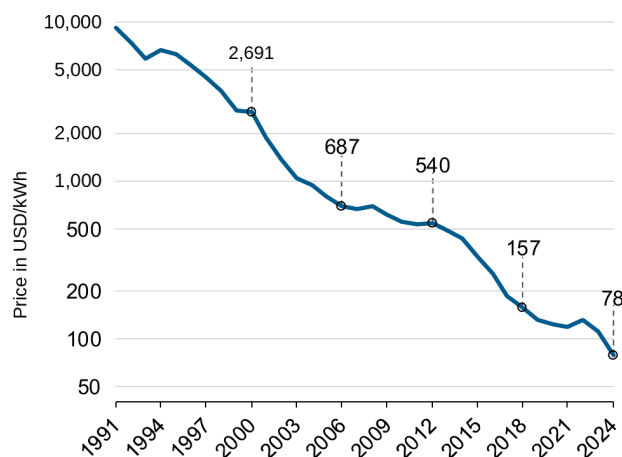
Battery storage with strong learning-curve effects

Against this background, battery storage – and lithium-ion storage in particular – is increasingly coming into focus as a means of smoothing grid load and electricity prices. Since 1991, their market prices have fallen by around 99% (Figure 1). Since 1998, this price decline can be explained by a learning rate of about 19%: with every doubling of cumulative lithium-ion capacity produced, prices fall by around 19%. Key drivers are the high modularity of the technology and continuous efficiency gains along the entire value chain.⁶ If this development continues, the price should fall by a further 19% or so by 2035 compared with 2024. This projection extrapolates the previous learning curve conservatively, if anything.⁷ The development is driven above all by electric mobility,

which accounted for 84% of global demand for lithium-ion capacity in 2025.^{8,9}

Figure 1: Price trend for battery storage cells

Prices for battery cells of lithium-ion batteries, price base 2024, logarithmic scale with base 2



Source: Our World in Data (2026), own illustration.

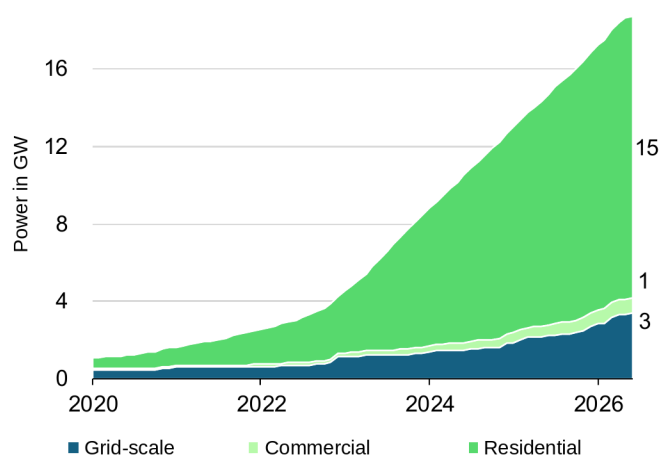
Expansion dynamics in Germany

Driven by this price decline, the diffusion of battery storage in Germany continues to increase. At the beginning of June 2026, total installed capacity in Germany stood at 19 GW of power with an energy capacity of approximately 29 GWh. In each case, that represents more than an eightfold increase over the last five years. At almost 80%, these storage units are predominantly residential systems, followed by grid-scale storage and industrial and commercial storage (Figure 2).¹⁰

Looking at grid connection requests and approvals for grid-scale storage suggests that this development will continue (Figure 3). In 2024, requests for 400 GW of capacity were submitted to distribution and transmission system operators. However, only 6% of these – 25 GW – were approved. Relative to the currently installed capacity of grid-scale storage, that is nevertheless a sevenfold increase.

Figure 2: Battery storage power in Germany

1 January 2020 to 1 June 2026



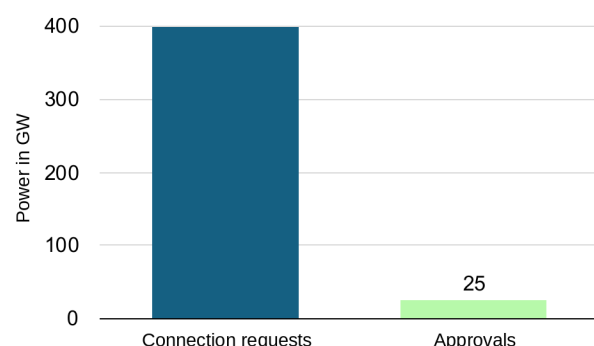
Note (translation): "Grid-scale" = utility-scale storage, "Commercial" = commercial and industrial storage, "Residential" = home storage. Labels at the right-hand edge show the values as at 1 June 2026 in GW.

Source: Battery Charts, own illustration.

Measured by the number of connection requests, by contrast, around 40% were approved. Consequently, it is particularly high-capacity grid-scale storage projects that do not receive approval, which suggests that the existing grid infrastructure is not keeping pace with the dynamic market development. It should be noted that an approval does not automatically lead to the storage facility being built.¹¹ There are thus two challenges: first, the approval of grid connections, which depends on grid expansion, and second, actual implementation, since not every approval results in construction – for example because of speculative applications or a lack of construction or installation capacity. According to the Marktstammdatenregister (the German core energy market data register), concretely planned additions up to mid-2030 amount to approximately 14 GW of grid-scale storage.¹²

Figure 3: Grid-scale storage: connection requests and approvals

Aggregated figures for 2024 in Germany



Source: BNetzA (2025, the Federal Network Agency), own illustration.

Within Europe, Germany has the largest storage fleet, followed by Italy and the United Kingdom. A characteristic feature in Germany is the high share of residential storage. In a global comparison, California, Texas, China as well as Japan and Australia dominate.¹³

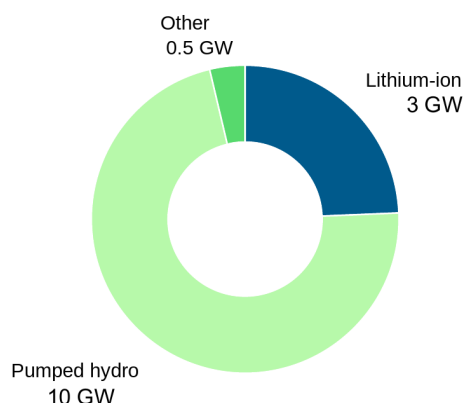
Technologies and fields of application in the German grid

Pumped hydro storage remains the dominant large-scale storage technology on the German electricity grid (Figure 4). Around 10 GW of capacity with an energy capacity of 55 GWh is connected.¹⁴ At full load, this results in a discharge duration of five and a half hours, meaning it could cover approximately 20% of average load in 2025.¹⁵ Its expansion, however, is barely scalable: the last significant extension of German pumped hydro capacity took place in 2004.¹⁶ An extension of an existing pumped hydro power plant

recently completed in Austria, adding around half a gigawatt of capacity, required around four years of construction time alone.¹⁷

Figure 4: Large-scale storage power on the German electricity grid

Including pumped hydro storage in Luxembourg and Austria connected to the German transmission grid; pumped hydro as at 1 January 2026; remaining data as at 1 June 2026; composition of "Other" and the calculation are set out in endnote 18



Source: Open Energy Tracker, Battery Charts, ISEA.

Battery storage accounts for the remainder of storage capacity on the German electricity grid. By now, this is almost exclusively lithium-ion storage (Figure 4). It is characterised by a high overall round-trip efficiency of 85 to 97%, a cycle life of up to 10,000 cycles and response times within fractions of a second. Unlike pumped hydro storage, for instance, energy capacity and power are technically closely coupled. That means: if the energy capacity increases – that is, how much energy can be stored – then power also rises, i.e. the speed at which the unit can be charged or discharged.¹⁹

In contrast to pumped hydro power plants, grid-scale battery storage has, for technical reasons, a higher ratio of power to storage capacity. It can therefore make large amounts of energy available in a very short time. However, this also comes with a shorter discharge duration. The lithium-ion grid-scale storage installed in Germany can thus feed out electricity for one and a half hours at full load. This makes it particularly suitable for short grid-supportive applications, arbitrage, limiting the cannibalisation of revenues of renewable installations, and bridging short periods of low generation from renewable sources.

A problematic aspect of lithium-ion batteries is that lithium extraction is concentrated mainly in a few countries: above all Australia, Chile and China.²⁰ In combination with strong global demand for electric cars and battery storage, this concentration makes the lithium price highly volatile. Production capacity is also heavily concentrated: 83% of global lithium-ion battery production takes place in China.²¹ Sodium-ion batteries are increasingly coming into focus as an alternative, because they have a comparable performance profile but manage with more readily available minerals. For want of economies of scale in still-young manufacturing, however, sodium-ion batteries have so far been more expensive and are not widely used.²²

Looking ahead, redox-flow batteries could also play an important role for the electricity market. Their advantage is that, in contrast to lithium-ion batteries, energy capacity and power are largely decoupled from each other. This means the batteries could be tailored more precisely to the respective application. Commercially, these storage systems have not yet achieved a breakthrough owing to persistently high costs and technological hurdles.²³ Similar hurdles are also holding back long-duration storage via electrolysis.²⁴

Behind the meter: residential and commercial storage

In Germany, residential storage accounts for the lion's share of battery storage (see Figure 2). These systems primarily serve to optimise self-consumption. As a complement to solar installations, they temporarily store surplus, self-generated electricity for later use. They lower the operator's electricity costs by increasing the share of self-produced electricity in total consumption. According to a model calculation, the grid supply costs of a representative household with a heat pump and an electric car can be reduced by 57% through a 10 kW photovoltaic installation together with a 10 kWh battery storage system. In addition, where a solar installation is already in place, storage can raise the degree of self-sufficiency by 28 percentage points.²⁵ Via a flexible grid tariff, residential storage can also charge directly from the grid. Intelligent energy management systems control charging and feed-in fully automatically on the basis of weather and consumption forecasts in order to minimise electricity costs.²⁶

Commercial storage pursues a similar purpose of self-sufficiency, but is also used to reduce peak loads. Short-term high grid offtake is then covered from a high-power storage unit. Beyond this, companies can hedge against power outages or frequency fluctuations and trade actively on the electricity market.²⁷

In front of the meter: grid-scale storage on the grid

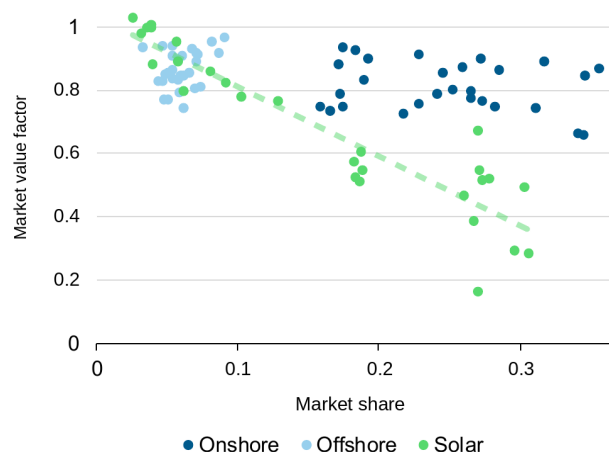
In contrast to residential and commercial storage, which operate behind the electricity meter, grid-scale storage is connected directly to the grid. There are various operational approaches here.

Grid-scale storage can be active in the market for ancillary services. Products traded here are aimed at stabilising the electricity grid. In this market, storage units guarantee as early as the previous day, at an auctioned price, to be available within a four-hour interval in order to feed in or absorb energy for a maximum of one hour when called upon. Which energy sources provide the ancillary services demanded, and to what extent, is not publicly documented. There is much to suggest, however, that storage is increasingly active in these markets. The prequalified capacity of storage doubled from 2024 to 2026, while it remained unchanged for other technologies.²⁸ Moreover, the discharge duration of grid-scale storage newly connected to the grid has increased. This indicates that it is increasingly targeting products with longer call-off durations: such products must deliver power for up to one hour at a stretch and therefore presuppose higher storage capacity. Among the various deployment strategies, they achieve the highest specific revenues per unit of capacity provided.^{29 30}

Battery storage can also counteract the cannibalisation of revenues of renewable energy installations. This phenomenon particularly affects photovoltaics: because a large share of installations generates electricity at the same time when solar irradiation is high, the market value of solar power is low precisely at those times. Aggregated at monthly level, this shows up in Germany in a falling market value factor, which relates revenues to the day-ahead wholesale electricity price. At the same time, the market share of solar power is rising (Figure 5). For wind, by contrast, this phenomenon is less pronounced owing to greater dispersion across the time of day and the seasons. Because of the continuing fall in costs for battery storage and rising competition among renewables, the IEA forecasts that by 2035 utility-scale photovoltaic installations combined with battery storage will be more profitable than those without storage, despite the additional investment costs.³¹ Storage can also lower the system costs of the energy transition: it reduces curtailment losses and thereby reduces the additions of generation and back-up capacity needed for the same climate target. How strongly depends on the cost ratio between storage and renewable energy.

Figure 5: A higher market share of renewable energy goes hand in hand with a lower market value factor

Aggregated shares per month since 1 January 2024 in Germany, trend line for solar



Note: The market value factor relates the average revenue of a technology to the average day-ahead wholesale electricity price. Values below 1 mean that the electricity is remunerated on average below the day-ahead wholesale price, for instance because many installations feed in simultaneously. At a very small market share the factor is close to 1; values above 1 would only be possible if generation occurred disproportionately in high-price hours.

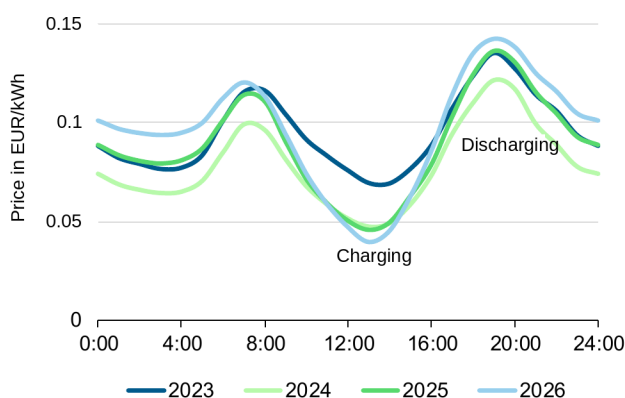
Source: BNetzA, Netztransparenz, idea: Open Energy Tracker.

Grid-scale storage can dampen electricity price fluctuations

Of particular interest is the arbitrage behaviour of storage: in Germany, estimates suggest that about a quarter of storage capacity is used for arbitrage.³² Storage exploits increasingly volatile electricity prices (Figure 6) by charging at times of low wholesale electricity prices and making the electricity available again at times of high prices. Growing solar expansion pushes prices down around midday, while morning and evening prices are higher, because power plants with high marginal costs deliver energy at those times. Often these are gas-fired power plants. The intraday market in particular, whose share of total electricity trading is steadily growing, is attractive for storage: short-term developments in energy supply are priced in more strongly here than on the day-ahead market.³³ In this use case, lithium-ion batteries have an advantage because of their high discharging and charging speeds.

Figure 6: Average wholesale electricity prices over the course of the day

Day-ahead wholesale electricity prices for the Germany/Luxembourg electricity market area, graphically interpolated, 2026 data up to 31 May 2026



Note: Because of the seasonality of solar power, the values for 2026 are only comparable to a limited extent with the full-year curves of previous years.

Source: BNetzA.

The current electricity market design, however, does not automatically ensure grid-supportive operation of grid-scale storage. Because a uniform electricity price applies in Germany, local grid congestion remains invisible to battery storage. Grid-scale storage relieves the electricity grid overall, but only as a by-product

of its market behaviour. In individual cases – for example in the event of a wind surplus that leads to local grid congestion – it can even exacerbate the problem: if a storage unit charges when prices are low zone-wide, even though the surplus wind power cannot reach it because of the congestion, controllable power plants on site have to cover its additional demand. Conversely, if a storage unit discharges in the surplus region when prices are high zone-wide, it places an additional burden on the local grid. In both cases, more wind power has to be curtailed.³⁴ As long as the uniform wholesale electricity price does not reflect regional scarcity, grid fees could take on this steering function. Dynamic grid fees that reflect spatial and temporal congestion could steer storage specifically to where it relieves the grid.³⁵

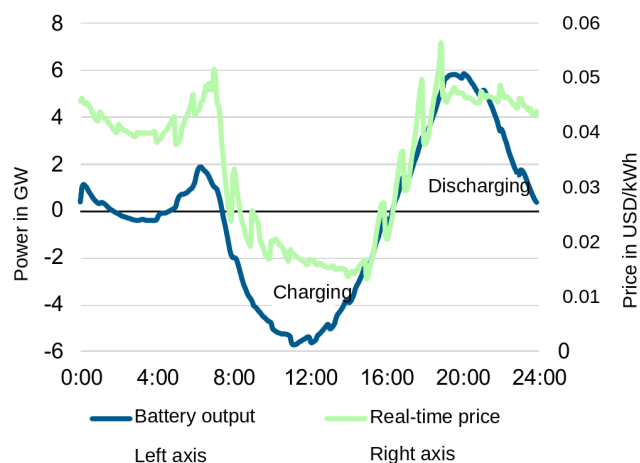
It can be assumed that, through their arbitrage behaviour, battery storage systems dampen the decline in wholesale electricity prices around midday, because they increase electricity demand in this phase. Conversely, they also moderate the rise in electricity prices in the evening hours. This is because they make cheap electricity from renewable energy sources available at a later point in time, so that fewer conventional power plants have to be ramped up. Granular data to quantify the concrete effect of charging and discharging is currently not publicly available for Germany. It is therefore worth looking to California, where the expansion of grid-scale storage is already much further advanced. Market design in California is, however, structured differently from Germany: trading intervals are more finely timed and local electricity prices favour the integration of renewable energy. Nevertheless, the mechanism by which storage affects the wholesale electricity price can meaningfully be transferred to Germany.

Example: California

In California, the data allows a look at the concrete behaviour of battery storage. Battery storage does indeed charge in the midday hours, when electricity prices are low, and discharges mainly in the evening and morning hours, when prices reach their peak (Figure 7).

Figure 7: Battery output and electricity prices over the daily profile

Average aggregated grid-scale storage output and five-minute real-time market electricity prices in the Californian grid, in each case for the period 1 January to 31 December 2025



Source: CAISO.

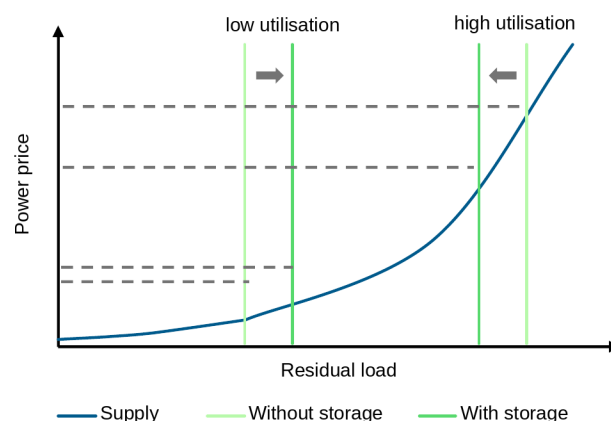
The main driver of electricity prices is residual load, which indicates how much electricity is not covered by wind and solar energy and therefore has to be provided by controllable power plants. Battery storage thus exploits price differences on the electricity market. It is active there as an arbitrageur. From a purely descriptive analysis, however, it is not possible to derive what concrete influence this behaviour has on the wholesale electricity price. This is because storage charges and discharges at these times precisely because prices are low or high, respectively. A comparison of prices in hours

with a lot and with little storage activity captures the operators' arbitrage rule, not its price effect. In addition, the behaviour and the expansion of grid-scale storage correlate strongly with the expansion of renewable energy sources and their feed-in, which in turn dampens the electricity price. A simple comparison of the electricity price in storage-intensive and storage-poor intervals conflates the effects mentioned. Moreover, retail electricity prices in California have risen in recent years for other reasons, for example because of higher surcharges for protecting the electricity grid against wildfires.³⁶

An article published in the academic journal *Econometrica* circumvents this problem. Instead of comparing prices, the study simulates how storage shifts, through its behaviour, the residual load that has to be covered by controllable power plants. The authors examine the years 2015 to 2019 and contrast the storage capacity that barely existed at the time with simulated storage behaviour. They first estimate how the wholesale electricity price depends on the utilisation of controllable generation capacity. In doing so, they observe a convex relationship: the more heavily this capacity is utilised, the higher the electricity price, and the more strongly it reacts to additional demand. The reason for this is the merit order: initially, power plants with low marginal and start-up costs step in; as utilisation rises, power plants with ever higher marginal costs increasingly come into play. Scarcity and market-power mark-ups amplify the effect further.

Figure 8: Simplified illustration of the mechanism

"Supply" is the supply curve of controllable capacity; demand curves are assumed, by way of example, to be perfectly inelastic



Source: Simplified illustration of the mechanism following Butters, R. A. et al. (2025). *Soaking Up the Sun: Battery Investment, Renewable Energy, and Market Equilibrium*, *Econometrica*, 93(3), 891–927.

Figure 8 presents this relationship schematically. Battery storage increases the residual load demanded at times of low utilisation, because it charges then. At times of high utilisation – the morning and evening price peaks – it lowers the residual load demanded, because it discharges then.

Because of the observed shape of the supply curve, discharging leads to a stronger fall in prices than charging raises the price. This is because, at times of low utilisation, charging by storage merely increases the volume demanded from power plants with low marginal costs, such as efficient combined-cycle gas and steam plants, so that the additional demand barely raises the price at all or – where there is a generation surplus from wind and solar energy – does not raise it at all. At times of high utilisation, however, discharging by battery storage lowers demand for residual energy, so that fewer of the more expensive gas-fired power plants have to step in. The arbitrage behaviour of storage therefore lowers the average wholesale electricity price. In the study, the effect of the first 5 GWh of grid-scale storage capacity is quantified as a 5.6% decline in the wholesale electricity price. As the storage fleet grows, however, this effect diminishes: expanding

an existing fleet from 25 GWh to 50 GWh lowers the wholesale electricity price by only a further 2.6%.³⁷

The model's core assumption is that wholesale electricity prices rise convexly as the utilisation of controllable energy capacity increases. This can plausibly be transferred to Germany. Here, too, it is predominantly controllable power plants that set the price along such a convex supply relationship.³⁸ As long as storage charges cheaply and discharges during the evening peaks, it presumably lowers the wholesale electricity price more when discharging than it raises it when charging. With a further growing solar share, this scope should initially increase, because deeper midday troughs widen the daily spread; working in the opposite direction is the diminishing marginal effect of a growing storage fleet. The orders of magnitude from California are not directly transferable, owing to the differences in market design mentioned above.

Grid-scale batteries smooth the wholesale electricity price in Germany as well

A central empirical question is whether the smoothing effect expected in theory is already measurable in Europe. This is examined in the following. For this purpose, a panel of 13 European bidding zones for the years 2023 to 2025 is used. The relationship examined is that between installed grid-scale battery capacity per gigawatt of a zone's peak load (the "dose") and the daily price spread as well as the hourly price profile. The analysis deliberately focuses on the installed fleet rather than on charging and discharging activity. This avoids the feedback of the price on storage behaviour, does not require feed-in data that is not publicly

available, and captures the price effect of all deployment purposes together. The box at the end of the article describes the methodology.

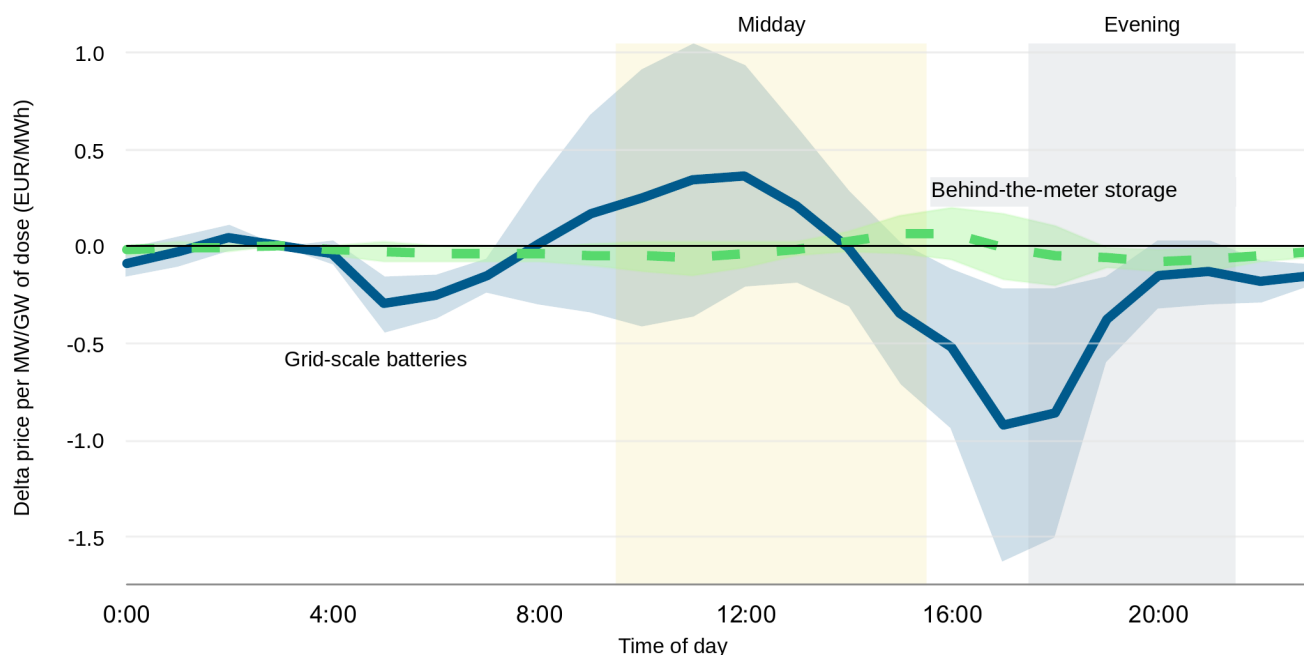
Figure 9 shows the central result. Plotted is the estimated effect of a battery dose that is one unit higher (1 MW of grid-scale storage per GW of peak load) on the hourly day-ahead wholesale electricity price, in each case measured relative to the reference hour at 3 a.m. This serves as a neutral point of comparison, because storage is typically barely active in this hour.

The effects are estimated jointly for grid-scale batteries and for residential and commercial storage. For grid-scale batteries, precisely the expected pattern emerges: midday prices (10 a.m. to 3 p.m.) are on average EUR 0.14/MWh per MW/GW *higher*, evening prices (6 p.m. to 9 p.m.) EUR 0.38/MWh *lower*. Midday minus evening therefore yields a spread that is EUR 0.52/MWh per MW/GW of dose narrower. Consequently, the daily curve does indeed flatten. This does not contradict the spread having increased over time (Figure 6). The smoothing effect means that the spread turns out smaller with more storage than it would have been without it.

For residential and commercial storage (behind the meter), by contrast, the profile is practically flat. This is to be expected economically: these storage systems are predominantly controlled according to self-consumption rules, are typically already fully charged before midday and do not offer their electricity on the day-ahead market.

Figure 9: Grid-scale batteries smooth the wholesale electricity price over the course of the day – residential and commercial storage does not

Estimated effect of an installed battery dose that is one unit higher (1 MW of grid-scale storage per GW of peak load) on the hourly day-ahead wholesale electricity price (in EUR/MWh) compared with the reference hour at 3 a.m. Joint estimation for grid-scale batteries (≥ 1 MW) and residential and commercial storage for 10 European bidding zones,³⁹ period 1 January 2023 to 31 December 2025; bands = 95% confidence interval. The box at the end of the article describes the methodology.



Source: Own illustration based on Moritz and Rode (2026) Do Batteries Smooth Electricity Prices? Unpublished manuscript; data: ENTSO-E Transparency Platform; Marktstammdatenregister of the Federal Network Agency; Joint Research Centre of the European Commission.

Point estimates at daily level indicate that a battery dose that is one unit higher for grid-scale batteries is associated with a reduction in the spread of EUR 1.5 to 1.7/MWh. Applied to the German additions of around 12 MW of grid-scale storage per GW of peak load between 2023 and 2025, these point estimates imply a reduction in the daily spread on the order of EUR 18 to 20/MWh – that is, around 17 to 19% of the German average daily price spread of EUR 108/MWh – and a roughly 16% lower dispersion of hourly prices over the course of the day. This extrapolation assumes a constant effect per unit. Because the marginal effect diminishes as

the storage fleet grows, the result should be understood as an approximation and not as an exact forecast.

Conclusion: storage works – barriers remain

Battery storage is an important lever of the energy transition. It can **smooth the daily curve of the wholesale electricity price** and support the market value of renewable energy. Expansion is market-driven and, given the continuing fall in costs, is likely to continue.

For this potential to be realised, **grid infrastructure must keep pace**. The high number of connection requests shows, on the one hand, the dynamism of the market and, on the other, the bottleneck at the grid connection stage, particularly for high-capacity grid-scale storage. Accelerated connection procedures and forward-looking grid expansion therefore appear central.

It must also be ensured that approved projects are in fact implemented, for instance by curbing speculative applications and addressing capacity bottlenecks in construction and connection.

At the same time, the current electricity market design does not automatically ensure grid-supportive operation: as long as the uniform wholesale electricity price does not reflect local scarcity, grid congestion remains invisible to storage. Dynamic grid fees that price in spatial and temporal congestion could steer the charging and discharging of storage to where it relieves the grid. The further development of the storage rules initiated by the Federal Network Agency points in this direction.

Technologically, there is much to be said for an open and diversified set-up. Lithium-ion storage dominates, but its raw material and production base is highly concentrated. Looking ahead, sodium-ion batteries could complement this role with readily available materials, while redox-flow systems and long-duration storage could enable longer discharge durations. The variety of use cases, from ancillary services to bridging periods of weak generation, cannot be served by one technology alone.

Untapped potential exists in **bidirectional charging of electric cars** as well as in **residential and commercial storage**, which so far contributes little to price smoothing. Regulatory hurdles relating to grid fees and electricity tax, as well as the absence of incentives beyond self-consumption optimisation, currently stand in the way of such deployment. If market design and the grid are developed accordingly, battery storage can fully unfold its role as a lever of the energy transition.

Box on the empirical methodology: how the smoothing effect is estimated

Theory and market observation from California suggest that grid-scale batteries flatten the daily curve of the day-ahead wholesale electricity price: they buy electricity in the cheap midday hours and sell it in the expensive evening hours. Whether this smoothing effect can already be demonstrated statistically in the European day-ahead market for the years 2023 to 2025 is examined in the following.

Data: The analysis uses hourly day-ahead prices from ENTSO-E⁴⁰ for 13 European bidding zones (Germany/Luxembourg, Belgium, the Netherlands, Northern Italy, France, Spain, Switzerland, Austria, the Czech Republic, East and West Denmark, Portugal and Poland). The United Kingdom is left out despite its large storage fleet, because since Brexit it has no longer been connected to European day-ahead market coupling and its prices are therefore only comparable to a limited extent. For Germany, the monthly time series of installed grid-scale battery capacity (from 1 MW, status “in operation”) comes from the Marktstammdatenregister of the Federal Network Agency; for the remaining zones, the European Energy Storage Inventory⁴¹ of the Joint Research Centre of the European Commission is used, validated against the Marktstammdatenregister and distributed over time using capacity addition figures from SolarPower Europe. Information on residential and commercial storage comes from the Marktstammdatenregister as well as from national sources. In total, the data set comprises around 14,000 zone-day and around 336,000 zone-hour observations.

The approach – installed fleet rather than activity: The analysis examines the relationship between installed storage capacity and the wholesale electricity price. It deliberately focuses on the installed fleet and not on actual charging or discharging activity. This is methodologically decisive: operators charge deliberately when prices are low and discharge when they are high. An analysis of activity would therefore only reflect this arbitrage rule, i.e. “explain” the price that triggers the behaviour in the first place, and would not measure any causal price effect. The installed fleet, by contrast, results from multi-year investment, permitting and grid connection decisions, is already fixed for the respective hour and cannot react to the current price. The measure used is the “dose”: installed grid-scale battery capacity per gigawatt of a zone’s peak load. This makes electricity markets of different sizes comparable. This strategy follows the equilibrium logic of Butters et al. (2025) and common recommendations on difference-in-differences approaches.⁴²

Two perspectives: The effect of the dose is tested on two quantities. First, on the daily spread, the distance between the highest and lowest hourly price of a day. A smoothing effect should reduce this. Second, on the hourly price profile over the day. Here the dose should raise midday prices and lower evening prices (Figure 9).

Netting out confounding influences: So that other developments do not distort the relationship, systematic patterns are netted out using fixed effects: zone effects capture the persistently different price levels of the countries, month-times-year effects capture common temporal shocks such as the rise in gas prices. For the daily profile, the following are added: zone-times-day effects for the day-specific price level (such as a zone-typical fuel price movement), zone-times-hour effects for the average daily profile of each zone, and hour-times-month-times-year effects for the common, time-varying shape of the “duck curve”. What remains is solely the zone-specific change in the shape of the day that goes together with the dose. Optionally, the estimation additionally controls for residual load, load as well as solar and wind generation. Statistical uncertainty is taken into account with standard errors that allow for correlations within a zone and within a day.

Placebo test with residential and commercial storage: A remaining objection would be that an unobserved third factor drives both storage expansion and the shape of prices. Such an influence would, however, have to act on every type of storage. Residential and commercial storage is therefore included in the same estimation as a comparison group. It charges according to self-consumption rules and does not react to day-ahead prices, so that a considerably weaker smoothing effect per megawatt is to be expected from it. If the smoothing shows up essentially only for the price-responsive grid-scale batteries, but not for the fleet of residential and commercial storage that is around five times larger in Germany, that argues against such a third factor.

Limits to what can be concluded: Four limitations should be borne in mind. First, the operating grid-scale battery fleet is on average still small over the period examined, so that a genuine smoothing effect is difficult to separate from random noise. Second, a register-based monthly time series is available only for Germany; for the remaining zones, the time path of expansion is determined approximately. Third, influences such as the differing fuel dependence of the zones during the gas price crisis, or cross-border market coupling, are not fully captured by the time effects. Fourth, the estimation is based exclusively on day-ahead prices; since storage is increasingly also active in intraday trading and in ancillary services, the overall effect is likely to be understated rather than overstated. A separation by deployment purpose is not possible. The results should therefore not be read as exact causal point estimates, but as consistent in direction and mechanism with price smoothing by grid-scale batteries.

1. See Rode, J. and D. Römer (2026). *Wind- und Solarstrom ergänzen sich* (Wind and solar power complement each other), Focus on Economics No. 530, KfW Research.
2. See Brüggemann, A. and J. Rode (2025). Chapter 13: *Wie entwickeln sich die Energiepreise weiter?* (How will energy prices develop further?) In KfW Research (ed.), *Wettbewerb(sfähigkeit) neu denken: Deutschlands Industrie am Scheideweg*.
3. Negative prices arise when inflexible generation exceeds demand. They are problematic because subsidised renewable installations nevertheless feed in and the difference is borne via the market premium from the EEG account (today essentially the federal budget); at the same time they indicate unused flexibility needs. For new installations, remuneration in negative-price hours has now largely been discontinued (Section 51 EEG, Solar Peaks Act 2025).
4. ENTSO-E (2026). BZN | DE-LU / Market / Energy Prices. ENTSO-E Transparency Platform.
5. See IEA (2025). *World Energy Outlook 2025*.
6. The data from Ritchie, H. and P. Rosado (2026, *Battery costs have declined by 99% in the last three decades, making electrified transport a reality*. Our World in Data) is methodologically based on a harmonised, inflation-adjusted time series of lithium-ion battery cell prices per kWh compiled by Ziegler, M. and J. Trancik (2021, *Re-examining rates of lithium-ion battery technology improvement and cost decline*, Energy & Environmental Science, 14, 1635–1651), which has been updated with more recent market data. For this purpose, Ziegler, M. and J. Trancik (2021) consolidate historical prices from industry, government and specialist sources. The price path describes the observed market price trend for battery cells normalised to capacity. It therefore differs from other approaches such as the levelised cost of energy storage (LCOS), which also factor in investment costs, operating costs, efficiency, efficiency losses and opportunity costs. This metric, too, shows historically and in the forecast up to 2035 a price decline comparable to that of cell prices. See BloombergNEF (2026). *Battery Storage Costs Hit Record Lows as Costs of Other Clean Power Technologies Increased*.
7. The price forecast for 2035 was produced by means of a Monte Carlo simulation on the basis of Wright's Law, methodologically guided by Schmidt et al. (2017, *The future cost of electrical energy storage based on experience rates*, Nature Energy, 2, 17110). A learning rate of 19% was assumed, which is consistent with Schmidt et al. (2017) and Ritchie, H. and P. Rosado (2026, *Battery costs have declined by 99% in the last three decades, making electrified transport a reality*. Our World in Data). In addition, annual capacity growth of 6.5% was assumed, back-calculated from the learning rate and the price path. The projection is thus based on an extrapolation of the current learning curve. Over 10,000 iterations, the model calculates cumulative capacity and the resulting cost degression according to Wright's Law. The uncertainties of the learning rate were modelled as truncated normal distributions and, in line with Schmidt et al. (2017), limited to the 80% quantile interval of the assumed distribution ($\pm 1.282 \sigma$) in order to exclude extreme values from the tails of the distribution. The annual growth rate, by contrast, was drawn untruncated (merely bounded at zero) so as not to narrow path uncertainty artificially. For 2035, the simulation yields a relative median price level of 0.81 relative to the base year 2024 (index 2024 = 1). The range between the 5th and 95th percentile of the simulation runs extends from 0.72 to 0.89.
8. See Breiter, A. et al. (2026). *Battery 2035: Building new advantages*. McKinsey & Company.
9. In electric mobility as well as in stationary battery storage, lithium-ion batteries dominate the market. The specific cell compositions used do differ – with lithium iron phosphate (LFP) as the dominant technology in stationary storage and nickel manganese cobalt oxide (NMC) as well as lithium nickel cobalt aluminium oxide batteries in electric cars – but the underlying production processes are very similar. In both cases the materials pass through comparable main manufacturing steps, from electrode coating through cell assembly to final formation. See Kwade, A. et al. (2018). *Current status and challenges for automotive battery production technologies*. Nature Energy, 3, 290–300. The production-process-driven price decline therefore runs in parallel between the two technologies. See Our World in Data (2025). *Lithium-ion battery cell prices by chemistry*.
10. Measured by energy capacity, 96% of these are lithium-ion storage systems, which is why in this study lithium-ion storage and battery storage are used synonymously unless cell chemistry is explicitly addressed.

The categories result from the two key figures of a storage unit: energy capacity and power. While power indicates the maximum energy output per unit of time, energy capacity defines the total energy reservoir. According to these key figures, storage is divided into three categories: residential storage with an energy capacity of less than 30 kWh and a power rating of less than 30 kW; analogously, commercial storage with less than 1 MWh (and MW) each and more than 30 kWh (and kW); and grid-scale storage with an energy capacity of more than 1 MWh (or 1 MW of power). See Battery Charts (2026). *Battery Charts*. Based on: Figgenger, J. et al. (2023). *The development of battery storage systems in Germany: A market review (status 2023)*, Working Paper.
11. See Bundesnetzagentur (2025). *Vom Antrag zum Netzanschlussvertrag: Status quo der Batteriespeicheranfragen 2024* (From application to grid connection contract: status quo of battery storage requests 2024).
12. In order to remain consistent in terms of power, the figure of 30 GWh reported by Battery Charts (2026) was converted, assuming a discharge duration of 2.2 hours. New grid-scale storage has had approximately this discharge duration since mid-2023. See Battery Charts (2026). *Battery Charts, Geplante Speicher* (planned storage). Based on: Figgenger, J. et al. (2023). *The development of battery storage systems in Germany: A market review (status 2023)*, Working Paper.
13. See Bloomberg (2026). *Energy Storage Market Outlook 1H 2026 More Records Ahead*. Bloomberg database.
14. See Aichner, N. et al. (2026). *Deutschland/Energiespeicher* (Germany/energy storage). Open Energy Tracker.
15. Bundesnetzagentur (2026). *Marktdaten* (market data).
16. See Aichner, N. et al. (2026). *Deutschland/Energiespeicher* (Germany/energy storage). Open Energy Tracker.
17. See Schwab, C. (2025). *Modernste „Batterie“ Österreichs geht in Betrieb* (Austria's most modern "battery" goes into operation). ORF.
18. The category "Other" comprises compressed air storage (62%) and alternative battery storage technologies (38%, excluding lithium-ion systems). The latter break down into lead-acid batteries (56%), high-temperature batteries (8%), NiCd batteries (2%), redox-flow systems (0.2%) and technologies not further specified (33.8%).

In the absence of technology-specific grid-scale storage data as at 1 June 2026, the power per technology type was approximated from the aggregated energy capacity data for that date from Battery Charts (2026). *Battery Charts*. Based on: Figgenger, J. et al. (2023). *The development of battery storage systems in Germany: A market review (status 2023)*, Working Paper) and the technology-specific grid-scale storage key figures as at 1 January 2026 from ISEA (2026. *Battery Status*), the technology-specific share of grid-scale storage energy capacity and the grid-scale storage discharge duration, assuming these two key figures to be stable over time. The old conditional shares were weighted with the current technology-specific total energy capacities, normalised to a share distribution and then scaled with the known current total grid-scale storage energy capacity, so that the estimate reproduces the observed aggregate grid-scale storage energy capacity stock. The conversion of the technology-specific grid-scale storage energy capacities approximated in this way into installed power was finally carried out via the technology-specific discharge duration from the older data, assumed to be stable over time. The resulting total power of grid-scale storage amounts to 3.55 GW and deviates by 4% from the actual value of 3.41 GW as at the reference date.
19. See Mahadevan, V. et al. (2025). *Critical review of energy storage systems: A comparative assessment of mechanisms, advantages, challenges, and integration with renewable energy*. Results in Engineering, 26.
20. See Our World in Data (2025). *Lithium production*.
21. See IEA (2024). *Batteries and Secure Energy Transitions*.
22. See IRENA (2025). *Sodium-Ion Batteries: A Technology Brief*.
23. See Sharmoukh, W. (2025). *Redox flow batteries as energy storage systems: materials, viability, and industrial application*. RSC Advances, 15(13), 10106–10143.
24. See Viswanathan, V. et al. (2022). *Energy Storage Grand Challenge Cost and Performance Assessment 2022*. Energy Storage Grand Challenge – U.S. Department of Energy.
25. See Weniger, J. et al. (2025). *Stromspeicher-Inspektion 2025* (Electricity storage inspection 2025). Solar Storage Systems Research Group – University of Applied Sciences (HTW) Berlin.
26. See Agora Energiewende and Forschungsstelle für Energiewirtschaft e. V. (2023). *Haushaltsnahe Flexibilitäten nutzen. Wie Elektrofahrzeuge, Wärmepumpen und Co. die Stromkosten für alle senken können* (Using household-level flexibility. How electric vehicles, heat pumps and the like can lower electricity costs for everyone).
27. See Uddin, M. et al. (2018). *A review on peak load shaving strategies*. Renewable and Sustainable Energy Reviews, 82, 3323–3332.
28. See Regelleistung.net (2026). *Präqualifizierte Leistungen in Deutschland* (Prequalified capacity in Germany).
29. See Battery Charts (2026). *Battery Charts*. Based on: Figgenger, J. et al. (2023). *The development of battery storage systems in Germany: A market review (status 2023)*, Working Paper.
30. The products described here in simplified terms as ancillary services are primary control reserve (frequency containment reserve, FCR) and secondary control reserve (automatic frequency restoration reserve, aFRR). FCR balances frequency deviations in the grid symmetrically in order to stabilise frequency at the target of 50 hertz. It is traded in four-hour slices. Prequalified storage units guarantee, across the slice traded, both to absorb and to deliver power. They must be able to provide their full capacity within 30 seconds and can be called upon for a maximum of 15 minutes. aFRR is likewise traded in four-hour slices and can be called upon for a maximum of 60 minutes. Here the full capacity must be available within five minutes, with an initial response required after 30 seconds. Positive and negative capacity are auctioned separately in this case. aFRR balances larger deviations, such as those arising from the outage of a power plant. See Regelleistung.net (n.d.). *Welche Arten der Regelreserve gibt es?* (What types of control reserve are there?).
31. See IEA (2025). *World Energy Outlook 2025*.
32. See Sauer, D. and J. Brucksch (2025). *Großspeicher als Schlüssel zur Systemflexibilität – Technik, Betrieb und Markttrends* (Grid-scale storage as the key to system flexibility – technology, operation and market trends). Institute for Power Electronics and Electrical Drives – RWTH Aachen.
33. See Timera Energy (2024). *Comparing intraday liquidity in European power markets*.
34. See Lohr, C. et al. (2025). *Netzdienlichkeit von Großbatterien* (Grid-supportiveness of grid-scale batteries), Neon Neue Energieökonomik.

35. See Monopolkommission (2025). *Energie 2025: Wettbewerb und Effizienz für ein zukunftsfähiges Energiesystem* (Energy 2025: competition and efficiency for a future-proof energy system). 10th sector report.
36. See Wiser, R. (2025). *Factors influencing recent trends in retail electricity prices in the United States*. The Electricity Journal, 38(4).
37. See Butters, R. A. et al. (2025). *Soaking Up the Sun: Battery Investment, Renewable Energy, and Market Equilibrium*. Econometrica, 93(3), 891–927.
38. See Geis, J. et al. (2026). *Price formation in a highly-renewable, sector-coupled energy system*. Energy Economics, 157.
39. Unlike in the point estimates at daily level, Portugal as well as East and West Denmark are not taken into account here, because no information on residential and commercial storage is available for these bidding zones. See also the box on the empirical methodology.
40. See ENTSO-E Transparency Platform (2026). <https://transparency.entsoe.eu/>.
41. See European Energy Storage Inventory (2026). <https://ses.jrc.ec.europa.eu/storage-inventory>.
42. See Butters, R. A. et al. (2025). *Soaking Up the Sun: Battery Investment, Renewable Energy, and Market Equilibrium*, Econometrica, 93(3), 891–927; as well as Baker et al. (2026). *Difference-in-Differences Designs: A Practitioner's Guide*. Journal of Economic Literature, 64(2), 498–557.