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Energy storage technologies and their role in grid decarbonization

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Introduction

The **electricity sector is in the midst of an unprecedented transition** driven by a combination of technology, policy and market factors. Central to this transition is the unabated **growth in wind and solar electricity generation** (often referred collectively as variable renewable energy, or VRE) and the **emergence of energy storage technologies**, driven by rapidly declining technology costs and increasing policy support[1,2]. In addition, there is growing interest in power system decentralization[3] as way to improve asset utilization and build resilience to disruptions – here, notable examples include localized production and consumption of energy (e.g. via distributed photovoltaic storage) as well as deployment of energy storage in distribution networks. On the demand side, economy-wide decarbonization efforts are driving the adoption of electricity in end-use applications in buildings and transportation as a way to reduce fossil fuel consumption[4].

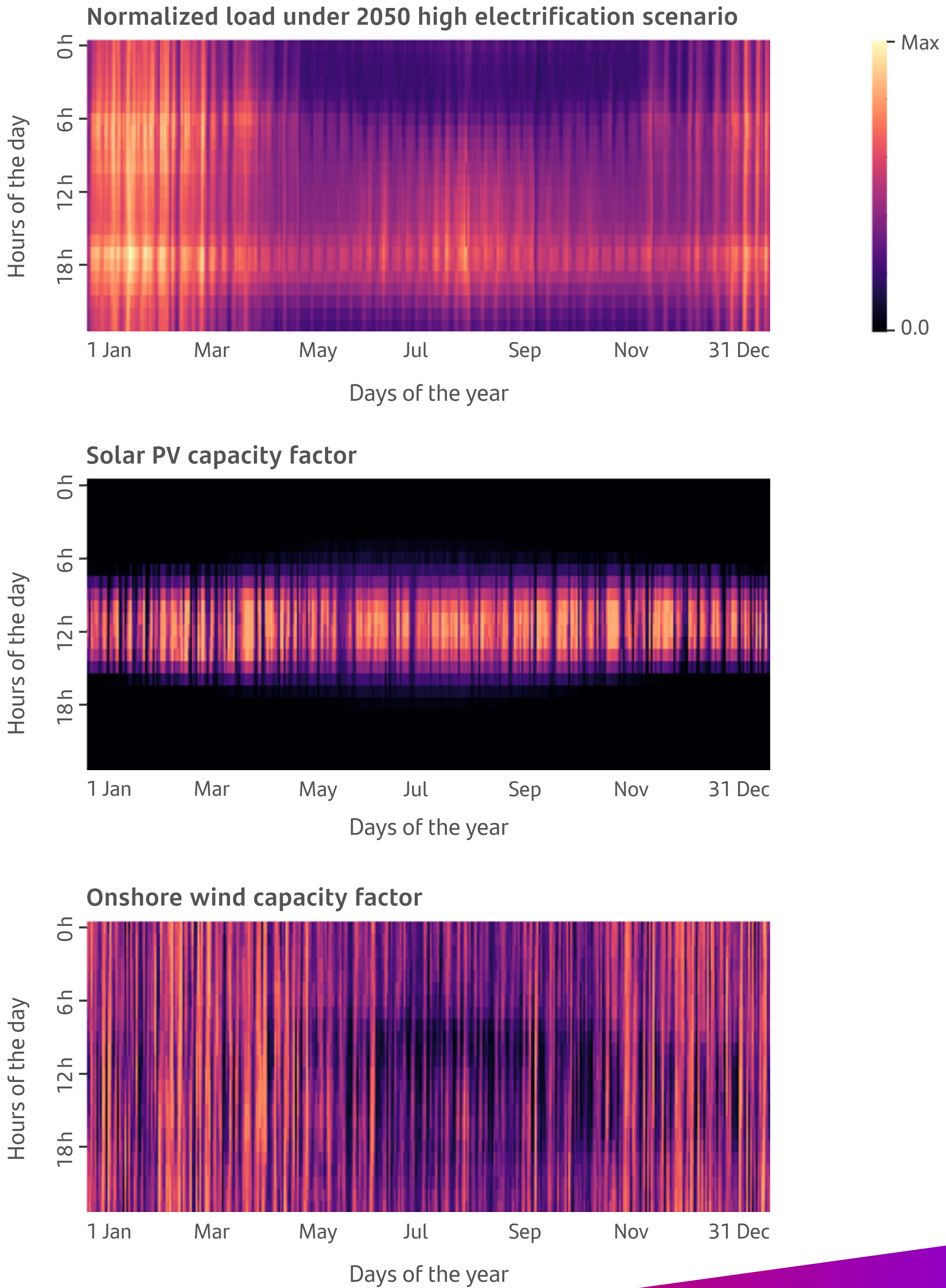
Taken together, these factors are likely to **significantly increase the spatial and temporal variability as well as weather-dependence of electricity supply and demand** compared to today's fossil fuel-dominated power systems. On the demand side, for example, electrification of buildings to displace fossil fuel use for heating in cold climate regions is likely to make electricity consumption more sensitive to weather and shift its occurrence from summer to winter – for example, **Figure 1A** highlights that electricity demand might peak in the winter (as compared to summer for the present system) for cold climate regions like New England in the U.S., under a scenario of high electrification across the economy, including buildings. On the supply side, the deployment of weather-dependent wind and solar generation as the primary levers for decarbonizing the power sector also introduces new challenges for power system operations as their output fluctuate over multiple time scales, as illustrated in **Figure 1B** and **Figure 1C**. For instance, solar power exhibits clear intra-day variations but also inter-day and seasonal variations (**Figure 1B**), while wind power availability tends to exhibit more complex temporal patterns, with lower availability during summer, as shown in **Figure 1C**. These considerations make it **necessary to invest in so-called flexible supply- and demand-side resources** whose consumption or output can be readily adjusted to help balance the power system balancing over multiple time scales. Today's power systems operate primarily on the principle that generation or supply follows demand, whereby the power output of fossil fuel generators, mostly natural gas power plants, are adjusted in response to demand fluctuations. However, as the decarbonization imperative grows, other flexible resources like **energy storage technologies are expected to play a greater role in balancing the grid**.

This paper presents an overview of alternative energy storage technologies and their role in future low-carbon electricity systems, while considering several attributes important to their commercial deployment (including technology cost and performance, scalability, and economic value proposition for grid applications). The rest of the paper is organized as follows. **Section 1** describes the **various use cases of energy storage in the power system**, provides a taxonomy for classifying alternative energy technologies, and summarizes the landscape of energy storage deployments today. **Section 2** discusses the value proposition of **short-duration energy storage technologies** like Li-ion batteries, which are currently driving the growth of the nascent energy storage market and have competing use cases, notably in electrifying transportation. **Section 3** discusses the value proposition of **long-duration energy storage technologies**, which are of increasing research and development interest in supporting grid decarbonization efforts by mid-century. The final section (**Section 4**) summarizes the key takeaways about the **outlook for energy storage technologies** in the context of grid applications, which are, in brief, the following:

- → A **portfolio of energy storage technologies** will be necessary for cost-effective and reliable decarbonization of the energy system, focused on VRE generation.
- → Through its **energy arbitrage function**, energy storage can serve as a substitute for other grid resources on both the demand and supply sides.
- → The integration of energy storage technologies **increases the complexity of power system operations and planning**, requiring improvements in modeling and software tools to accurately represent these complexities.

Figure 1. Illustration of temporal variability in electricity demand under high electrification futures as well as solar and wind resource variability.

Data corresponds to New England region in the U.S. Electricity demand scenario corresponds to 2050 deep decarbonization scenario from a literature report[5].



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Storage use cases, characteristics and state of market

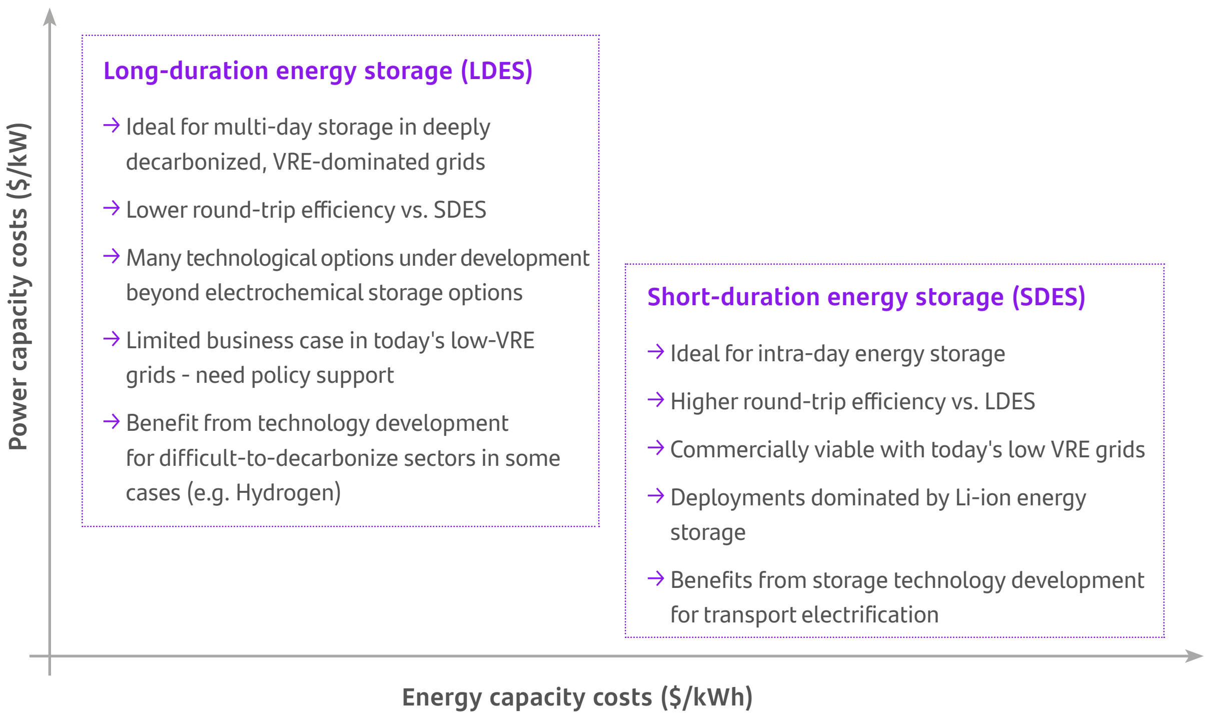
Energy storage technologies **enable time-shifting of energy**, i.e. moving electricity supply from one time period to another, creating the possibility of several valuable applications throughout the entire electricity supply chain. At the bulk power system level[i], energy storage makes it possible to defer investments in generation and transmission, improve the utilization of VRE supply (by reducing its curtailment), reduce thermal generator start-ups (and associated emissions), as well as reduce transmission losses. **Storage can and has been used to provide a variety of ancillary services that are required to meet reliability criteria at the bulk power system level**. For example, in 2019, about 75% of battery storage installations in the U.S. (750 MW) were involved in frequency regulation services[6]. In general, grid-level ancillary service needs tend to be smaller than capacity requirements for electricity supply and therefore mainly represent an important short-term driver of storage value and deployment. **At the distribution system level, the use of storage can reduce operating losses and defer investments to support end-use electrification**[3]. Another potential distribution system application that is attracting increasing interest is the use of storage by customers to minimize their peak consumption and thus avoid often-punitive demand charges.

Unlike power generation technologies, energy storage technologies have at least two and possibly **three dimensions of capacity**. A key dimension is the *energy storage capacity*, which is measured in megawatt-hours (MWh) and represents the maximum amount of energy that a facility can hold. In addition, similar to power generators, a storage facility will be associated with a maximum instantaneous power it can supply to the grid, or *discharge capacity*, which is measured in megawatts (MW). For some technologies, the maximum instantaneous power a facility can draw from the grid—also called its *charge power capacity*—can be different from its *discharge power capacity*. The relationship between a facility's energy storage capacity and its maximum discharge power capacity is its duration, measured in hours. This is the period of time during which the facility can provide maximum power, starting from a full charge. Most existing battery storage facilities currently have durations of four hours or less and are often referred to as short-duration storage[6]. Aside from capacity, other metrics of importance for storage facilities include: a) its *round trip efficiency,* which indicates the fraction of energy used to charge the storage that is available for discharging and b) *self-discharge rate*, which represents the rate of loss of stored energy over time, which impacts the duration over which one might want to economically hold energy in storage.

i. This refers to the high-voltage transmission system (typically ≥ 69kV) and MW-scale generation resources connected to it.

Energy storage technologies can also be classified based on the medium of energy storage, ranging from electrochemical, chemical, thermal, and mechanical storage[7,8]. All of these technologies can perform the core function of **energy arbitrage**, consuming electric energy during periods when VRE output is abundant and electricity prices are relatively low, and generating electric energy during periods when VRE output is scarce and electricity prices are relatively high. Storage technologies can be further classified based on the types of grid use cases for which they are likely to be best suited (**Figure 2**). In general, **technologies with high energy capacity costs and low power capacity costs are best suited for shorter duration storage applications** (up to a few hours) and multiple charge/discharge cycles within a day[7-11]; Li-ion batteries are the best example of short duration energy storage technologies. In contrast, **technologies with low energy capacity cost are best suited for storage applications with longer duration (up to several days) and less frequent cycles;** various thermal (e.g. molten salt storage), chemical (e.g. hydrogen), mechanical (e.g. pumped storage hydro) and electrochemical storage (e.g., metal-air batteries, redox flow batteries) technologies fall into the category of so-called long duration energy storage (LDES)[ii] technologies[8,10,11].

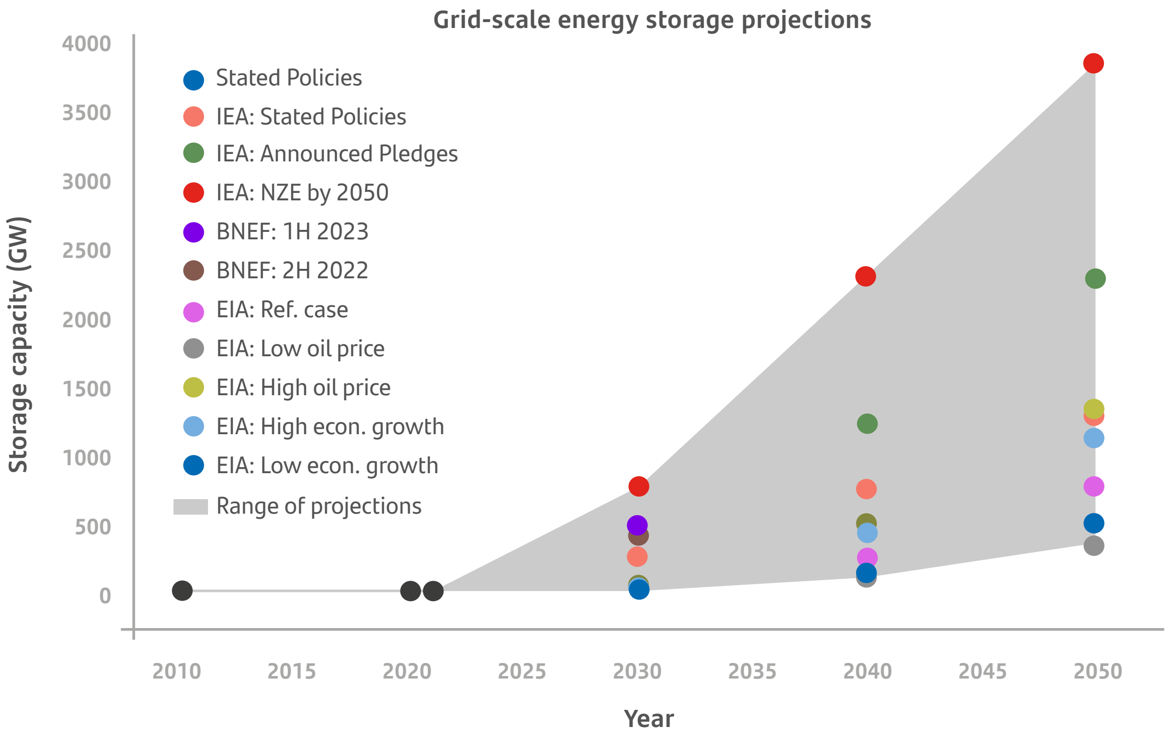
Figure 2. Classification of energy storage technologies based on their power and energy capital costs and grid applications.



ii. The term 'long-duration energy storage' (LDES) is often used to refer to various storage technologies that are expected to be both technically and economically suitable to cycle energy storage capacity infrequently and store energy in sufficient amounts to sustain electricity production over periods of days or weeks.

As of 2022, the **global installed stationary energy storage capacity** amounted to 177 GW and 777 GWh[12], which is relatively small when compared to global installed electricity generation capacity (8185 GW) and annual electricity generation in 2021 (28,333 x 10^3 GWh)[13]. Much of the installed energy storage capacity today is in the form of **pumped storage hydro facilities**, which is a form of mechanical energy storage in which water is pumped into an elevated reservoir during the charging phase and released into a lower reservoir during the discharging phase. However, with the exception of China, deployment of pumped storage hydro facilities, which typically have duration of twelve hours or more, has slowed in many regions where significant capacity has been installed, such as the U.S. This is due to challenges in siting, high initial costs, competition with flexible power generation from cheap natural gas, and inflexible size compared to new modular battery storage technologies such as Li-ion[7]. However, as the share of VRE generation in power grids increases, there is renewed interest in pumped hydro storage deployments as well as a range of other energy storage technologies, especially short duration battery storage deployment. This growing interest in energy storage for grid applications is reflected in the **projections by various groups for energy storage capacity deployment** over the next 2-3 decades, illustrated in **Figure 3**.

Figure 3. Range of projections for grid-scale energy storage capacity over the next 2-3 decades.



Data sources include: scenarios from International Energy Agency (IEA), World Energy Outlook 2022, scenarios from U.S. Energy Information Administration International Energy Outlook 2021, and Bloomberg New Energy Finance (BNEF) projections from 2nd half of 2022 (2H 2022) and First half of 2023 (1H 2023).

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Value proposition of short-duration storage for grid applications

Short-duration storage applications and value in bulk power systems

The **cost of Li-ion battery storage has dropped significantly** over the past decade, opening up its market deployment beyond consumer electronics applications and into electric vehicles (EVs) as well as stationary (power sector) applications. In the power sector, Li-ion battery storage is used for a variety of end-use applications ranging from demand-side applications to bulk power systems, which includes uses like **frequency regulation** and supporting VRE integration. The rapid growth of VRE generation in many power grids in all regions is accelerating the deployment of battery storage to support their integration. For example, utility-scale battery storage installations in the U.S. have more than tripled from 1.4 GW in 2020 to 4.6 GW by the end of 2021[14].

The energy arbitrage function of energy storage drives its economic value by reducing the operating and capital costs of the power system. **Figure 4** illustrates how the economic value of Li-ion energy storage installations is expected to change as a function of grid context, the level of VRE generation, and the level of storage deployment. In general, the **economic value of energy storage increases with the share of VRE generation**, since storage enables time-shifting weather dependent VRE electricity supply to match temporal patterns in electricity demand. In this way, energy storage deployment increases the utilization of VRE generation capacity, and thus reduces the total VRE capacity investment required to achieve a given decarbonization target. This capacity substitution impact of energy storage is central to its economic value, but its implementation in practice will depend in part on how energy storage is treated in capacity renumeration mechanisms (capacity markets) in regional electricity markets. Outside of electricity markets, developers and integrated utilities in regulated markets can implicitly capture capacity substitution value through the **integrated development of wind, solar and energy storage projects**. Recent trends confirm the observation that this may be a preferred method for monetizing the capacity substitution value of storage - for example, at the end of 2022, more than 450 GW of solar capacity at various stages of the grid interconnection process in the U.S., are **hybrid projects** that include the co-located storage deployment[15].

Figure 4 also highlights that the **value of storage depends not only on VRE generation levels, but also on its composition**, i.e., the contribution of wind and solar, which is dependent on relative costs of both technologies and their regional resource availability. Although capital costs ($/kW of nameplate capacity) of solar PV are generally lower than onshore and offshore wind generators, their resource availability, measured by the metric *capacity factor*[iii], tends to be lower in many regions (e.g. U. S. Northeast, U.S. Gulf coast, Europe, Southern India). This means that the **cost-effective portfolio of VRE generation for grid decarbonization will vary from region to region**. In this context, the value of storage tends to be greater in power systems where either solar or wind dominates (e.g., the New England-like system in **Figure 4**), compared to systems with high quality solar and wind resources (e.g., the Texas-like system in **Figure 4**[iv]). Moreover, the diurnal nature of solar energy leads to strong synergies with Li-ion, which is ideal for intra-day storage applications, as noted earlier.

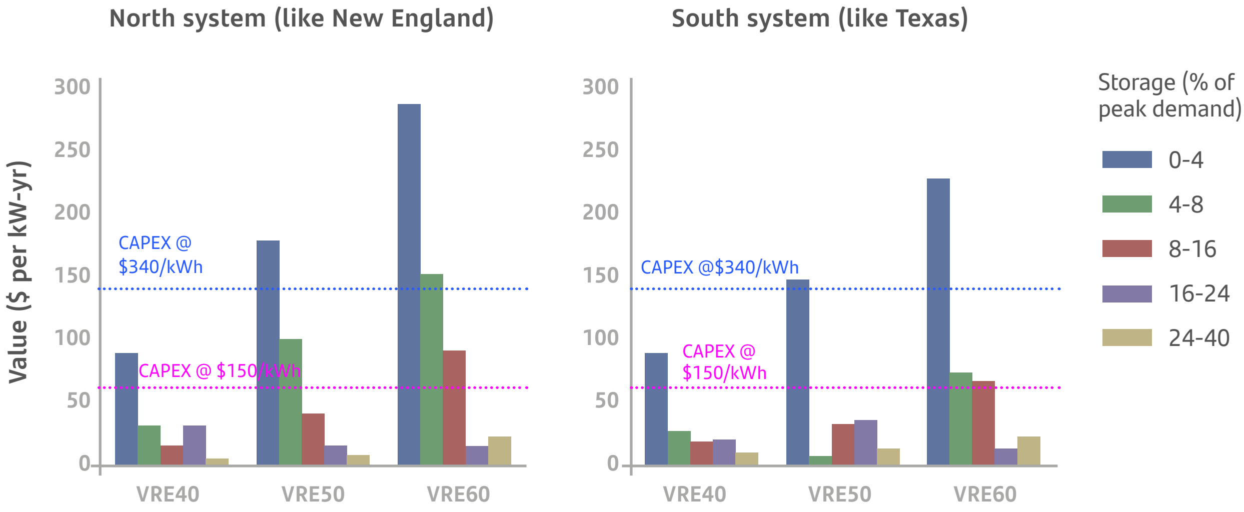
Similar to other power system resources, like solar, the system value of storage declines with increasing storage penetration due to increasing competition for the limited number of energy arbitrage opportunities (as shown in **Figure 4**). While this phenomenon is partially halted by increasing VRE generation, it also points to the importance of further reducing the cost of energy storage technologies to enable their cost-effective deployment (i.e., value is greater than cost) at scale to support VRE integration and grid decarbonization. In this context, it is important to recognize that the economic value of arbitrage services provided by storage to support integration of VRE may be adversely impacted by other trends impacting power systems. One factor is projected reductions in VRE capital costs, particularly solar, which could reduce the value of storage obtained from VRE capacity deferral. A second factor is the increasing interest of regulators, utilities, and other firms in using demand-side resources to balance the energy system. In particular, it may be plausible to provide the same services as short-duration Li-ion energy storage by shifting consumption of electricity over time, such as for electric vehicle charging (e.g. delaying charging from the evening to late night when electricity demand is low, or in the middle of the day)[16,17]. Such **demand-side flexibility directly competes with supply-side Li-ion storage deployments** when it comes to energy arbitrage opportunities, and therefore could reduce their deployment.

iii **Capacity factor** is the ratio of the annual average energy production (kWhAC) of an energy generation plant divided by the theoretical maximum annual energy production of a plant assuming it operates at its peak rated capacity every hour of the year. Typical values of utility-scale PV facilities at the best locations generally greater than 20%, while for wind, the typical value at the best sites could be greater than 40%. For context, the average capacity factor of the natural gas combined cycle power plant fleet in the U.S. was 57% in 2020.

iv Examples of other regions outside the U.S. with similar characteristics as Texas system discussed in Figure 3, include Chile, South Australia, and parts of India. Non-U.S. regions with similar characteristics as New England system include: U.K., Ireland, and parts of Northern Europe.

From a societal perspective, this may be beneficial in reducing the material need for grid decarbonization and lowering the overall cost of the power system by foregoing investment in physical assets in lieu of incentivizing potentially lower-cost "virtual" assets (e.g., gathering customers willing to shift their consumption in response to grid needs). A third factor is the **extent of inter-regional transmission expansion** that allows for exploiting spatial differences in VRE supply to manage their temporal variability. Transmission expansion can reduce the system cost of bulk power system decarbonization by reducing investment in VRE generation and energy storage capacity[18].

Figure 4. Marginal economic value of energy storage as function of storage deployment levels (as % of peak demand) and variable renewable energy (VRE) generation levels across two power systems with demand and VRE resource characteristics similar to New England (North) and Texas regions (South), respectively.



The labels VRE40, VRE50, VRE60, refer to modeled scenarios with 40%, 50%, and 60% of total generation provided by VRE resources. The blue and purple horizontal lines correspond to the annualized capital cost per kW of storage for 4-hour battery duration based on typical current cost and future cost projections. These annualized costs are calculated from installed capital costs using a lifetime of 15 years and a discount rate of 8.1%. These capital cost do not impact the calculation of the value of storage estimated but rather provide a point of comparison to the value of storage estimates presented.

Opportunities for short-duration storage in distribution networks

Along with their deployment on the bulk power system, the modularity of energy storage also creates opportunities for its use across electricity distribution networks, from the substation to the point of consumption, to **improve infrastructure use efficiency, cost, and reliability**. The deployment of these so-called **distribution level storage (DLS) assets** can provide the same services as more centralized electricity resources, including utility-scale energy storage, but at the points in the power grid where they are most valuable. If sited at the right locations and operated at the right times, DLS can deliver more locational value[v] than centralized resources. However, DLS also tend to cost more on a per-unit basis than their centralized counterparts, which is due to economies of unit scale[3].

Broadly speaking, there are three main electricity services that exhibit locational value: electrical energy, network capacity (or 'non-wires' alternatives to network capacity), and enhanced reliability or resilience[3,19]. In particular, DLS can provide locational value within distribution networks by a) **complementing other distributed energy resources** (e.g., rooftop photovoltaic) to provide energy in areas with high marginal energy losses associated with provision of supply from the bulk power system, b) providing local power supply to **reduce peak electricity consumption**, as seen by the bulk power system, in areas of the distribution network that would otherwise require network upgrades, and c) supplying energy to meet demand during **network outages**[19].

Globally, electrification trends related to the **adoption of EVs and electrified heating, ventilation, and air conditioning systems are likely to lead to an increase in peak electricity consumption** that will require further investment in distribution networks –for example, the International Energy Agency (IEA) expects annual grid investment to increase by >200% by 2030 compared to 2020 levels[20]. The deployment of DLS can help defer some of this investment by leveraging their energy arbitrage function. For example, deploying DLS with high-powered EV charging stations can reduce electricity sourced from the bulk power system during periods of peak demand, thereby reducing the sizing of the wires and substation capacity serving those stations[17,21]. Similar applications exist in urban environments in many emerging markets with hot and humid climates (e.g., India, Indonesia), where air conditioning, rather than EV charging, is the primary driver of projected demand growth[22]. In this geographical context, the combination of high financing costs and more congested urban distribution networks compared to high-income economies (e.g., U.S.) makes the use of DLS as a non-wire alternative to deferring expensive distribution network upgrades economically attractive today[7,23].

v The concept of **'locational value'** refers to the fact that the same asset deployed at two different locations in the electricity network might provide different economic value (i.e. cost savings) to the system, due to the physical characteristics of the network at each location (E.g. different marginal energy losses, capacity limits of network components).

Another driver for DLS adoption is to **improve energy access in low-income countries** with previously unreliable bulk electricity systems. In such situations where grid supply is limited, either by available generation capacity and/or network extent and access issues (e.g., sub-Saharan Africa and parts of rural India), stand-alone minigrids and solar-home systems with energy storage can serve as an alternative and environmentally friendly mode of electricity supply that also improves energy access. The economic viability of these applications will depend on the nature of the reliability challenges facing the bulk power system (e.g., predictability and frequency of outages) and may be short-lived given the growing desire of governments and regulators in these regions to improve overall grid reliability.

04

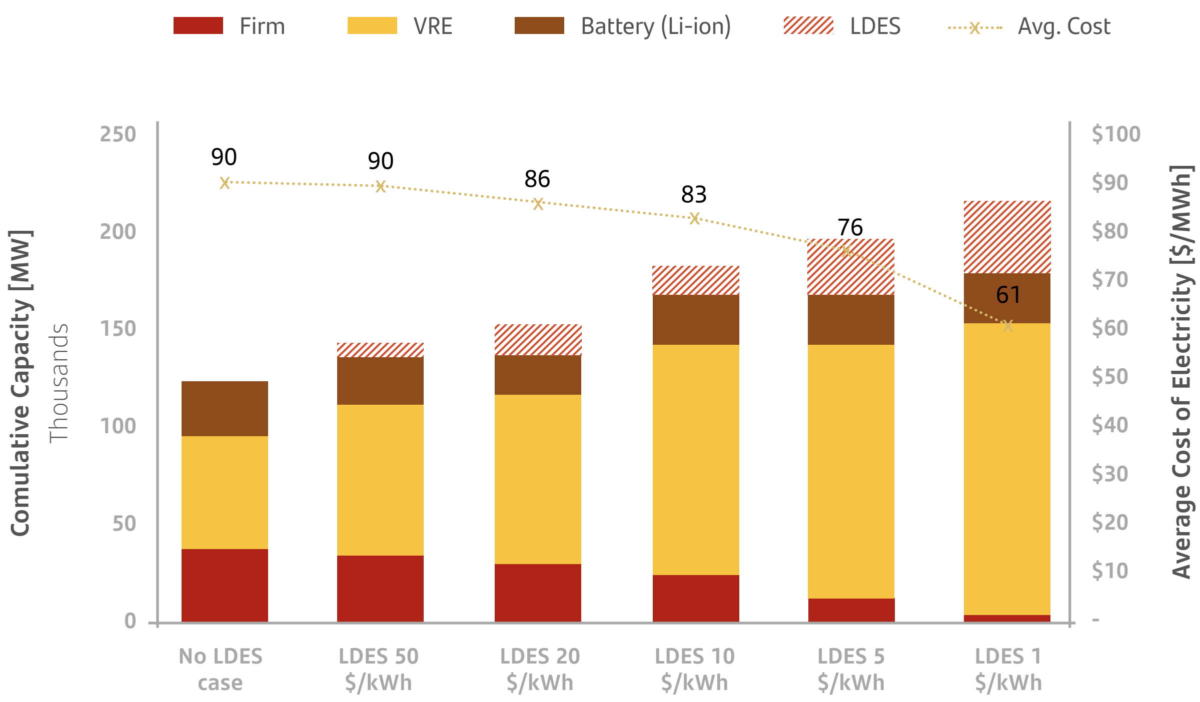
Opportunities for emerging, long-duration energy storage technologies

Power systems with high share of VRE generation **need to manage their fluctuations over multiple time scales**, including variations in output over the course of a day, several days, and perhaps even weeks. As shown in **Figure 1**, the intermittency of VRE supply, as well as the increasing weather dependence of electricity demand, presents an increasing challenge to balancing supply and demand in scenarios with high levels of electrification. Li-ion battery storage systems, whose costs have dropped significantly over the past two decades, are ideal for short-duration energy storage due to their relatively low power capital costs (about $240/kW as of 2021, according to one estimate[24]) and relatively high round-trip efficiency (about 85%). However, their energy capital cost, which is about $250-300/kWh today[24], makes them uneconomical for energy storage installations beyond rated durations of 4 to 6 hours[25]. Moreover, the future cost trajectory for Li-ion battery storage is likely to be bounded by the cost of the materials used[26], with projected 2050 energy capital costs in the range of $70-$110/kWh[7,8,10,24]. In this context, several studies have highlighted that **LDES technologies with lower energy storage capacity costs that enables longer storage duration deployment, could be critical for cost-effective electricity system decarbonization**.

Previous modeling studies to characterize cost and performance targets for LDES technologies have shown that LDES systems need to achieve energy capital costs below $50/kWh and ideally near or below $20/kWh[7,27,28] to be cost-effective for deployment as part of decarbonized, VRE-dominated power systems (see **Figure 5**). While Li-ion energy storage is not well suited for LDES deployments in decarbonized power systems, there are many emerging technologies in the electrochemical, thermal, mechanical and chemical storage categories that can potentially achieve these cost targets. Notable examples include: **a) redox flow batteries, b) metal-air batteries, c) hydrogen storage, and d) thermal energy storage**. Compared to Li-ion battery storage, these LDES technologies have the potential to achieve lower energy capacity costs, albeit with higher power capacity costs, and lower overall round-trip efficiency. At the same time, LDES technologies are not best suited for intra-day energy arbitrage due to their high-power cost and low round-trip efficiency, which means that they **will likely complement rather than replace Li-ion storage in bulk power systems**.

From a technology design perspective, the **capital cost of LDES** is the most important determinant of its economic value to the power system, followed by its **discharge efficiency**, implying that efforts to improve these attributes of the emerging technologies are likely to yield the greatest economic returns. In addition, studies suggest that optimal LDES operation in decarbonized grids is likely to involve long charging times followed by faster injections of electricity into the grid during periods of low VRE availability[9]. Consequently, LDES systems in which the rate of charging power capacity and discharging power capacity can be independently sized, as is the case with most thermal, chemical, and some mechanical storage technologies, may have an advantage over systems without this feature (e.g., most electrochemical storage technologies).

Figure 5. Illustration of the impact of LDES technology availability and energy capital cost on decarbonized power system capacity mix (left y-axis) and cost (right y-axis).



Results adapted from a modeling study of decarbonized power system with demand and VRE resource characteristics resembling the New England region in the U.S under 2050 technology cost assumptions[9]. "Firm" resources refer to low-carbon dispatchable generators and includes nuclear, fossil fuel generation with pre-combustion and post-combustion carbon capture technologies.

Studies modeling LDES investment and operation as part of cost-optimized, decarbonized power systems[7,9,29] show that the **value of these technologies increases with more stringent grid decarbonization requirements and increased reliance on VRE generation**. In such a context, adoption of low energy capital cost LDES technologies can reduce the average system cost of electricity by reducing the need for dispatchable generation (e.g., fuel-based generators, nuclear power) and VRE curtailment (see **Figure 5**). The availability of power plants with high operating and low capital costs that complement the low capital and high operating cost of VRE technologies is likely to reduce the value of LDES technologies for system balancing. Fossil fuel-based power plants without carbon capture and storage (CCS) and power plants fueled by low-carbon hydrogen are two notable examples of generators with high operating and low capital costs. As long as CO_2 emissions regulations permit their utilization, fossil fuel power plants, particularly existing natural gas assets backed by existing natural gas storage and transport infrastructure, will compete directly with LDES technologies to meet the multi-day balancing requirements of power systems with high share of VRE generation. This suggests that **market factors alone may not be sufficient to incentivize large-scale deployment of LDES technologies, and that more targeted actions may be necessary**. These include governmental support of LDES research and development and pilot projects to make these technologies available in a timely manner to meet regional and global climate goals. A favorable development to support LDES scale-up might be the growing interest of businesses to match their energy consumption with renewable energy supply on a 24/7 basis. Another development is the emergence of regional regulations for the deployment of storage systems (e.g. energy storage mandate in California), as well as policies to subsidize the costs of LDES technology adoption (e.g., investment tax credits under the U.S. Inflation Reduction Act of 2022).

Among LDES technology options, chemical energy storage candidates such as **hydrogen**, and derived energy carriers (e.g., methane, ammonia) have the potential to achieve very low energy capital costs[29–31] and uniquely exploit additional revenue streams due to the value of the underlying storage medium in decarbonizing other end-use sectors[31–33]. In particular, electricity-based production of hydrogen could provide a large flexible electricity demand-side resource that can support the integration of VRE into the power sector, while also being used to displace use of fossil fuels in difficult-to-electrify end-use applications (e.g., heavy-duty transportation, high-temperature industrial heat). This approach of **using H_2 to balance the power system** is potentially more compelling than its "conventional" use case as a exclusive LDES technology (i.e. power to H_2 to power and without use of H_2 outside the power sector), since the latter involves additional capital expenditures and additional energy losses associated with the H_2 to power conversion step. In any case, using H_2 for power system balancing **requires further cost reductions and scale up of electrolyzer technologies** that split water using electricity to produce H_2 – these technologies accounted for less than 1% of the global H_2 production of 94 million tons in 2021[34].

Thermal energy storage technologies, which have been commercially deployed to date to improve the capacity utilization of solar thermal power plants, offer a unique opportunity in the near future to **repurpose power generation equipment in existing fossil fuel power plants**. Specifically, thermal energy storage, in conjunction with resistive heaters or heat pumps that draw electricity from the grid to charge the thermal storage medium (e.g. molten salt) and a heat exchanger, can replace the fossil fuel-fired boiler to generate steam to drive the existing power cycle in periods of discharge. Steam Rankine cycles, that are the mechanism for power generation in coal-fired power plants, have peak temperatures of about 600°C and plant thermal efficiency of 30-45%. Molten salts being considered for thermal energy storage can provide heat at a maximum temperature of ~550°C. Such concepts are being contemplated for deployment in the U.S. may find most value in regions of the world where the coal power plant fleet is larger, under-utilized and is relatively young (e.g. India, Indonesia, Vietnam). By repurposing existing coal plants in disproportionately burdened communities that are economically tied to the coal industry, thermal energy storage retrofits also offer the socioeconomic benefit of preserving power plant jobs and local revenues, thereby **supporting a fairer energy transition**.

Roadmap for future action

Energy storage technologies will play a pivotal role in the cost-effective decarbonization of the power sector, thereby supporting beneficial electrification of end-uses to enable economy-wide decarbonization. The cost-optimal composition of storage technologies and their role will depend on several geographic, technological, and regulatory factors, most notably: a) the composition and reliance on VRE generation for grid decarbonization, b) the temporal patterns of electricity consumption, and c) the availability of competing supply- and demand-side resources to support system balancing over multiple time scales.

While the majority of energy storage technologies deployed today are pumped hydro storage systems, future growth is likely to come from a broad range of technologies, **beginning with the deployment of Li-ion storage** already underway today.

The diversity of energy storage technologies and the inter-temporal coupling they introduce in power system operations has two major implications.

First, **simplistic economic assessments** of energy storage technologies that do not adequately consider their dynamic interactions with the power system, but instead use a static or simplified dispatch profile, **are likely to lead to misleading findings about the relative competitiveness of different technologies.**

- → Instead, system analysis, such as the use of power system dispatch or capacity expansion models, will lead to a more holistic and nuanced view of the economic competitiveness of alternative energy storage technologies and their interaction with other grid resources.

Second, the **cost-optimal deployment of energy storage cannot be reduced to simplistic economic principles** such as merit-order dispatch (i.e. ranking energy sources by their cost and using the cheapest first), as observed in the case of cost-optimal deployment of power generators, which increases the complexity of operating and planning power systems with significant storage deployment. This complexity is exacerbated when uncertainty and inter-annual variability in VRE generation and electricity consumption are considered.

→ Therefore, there is a need for advanced software tools for a) power systems planning and operations considering the role of storage, and b) efficient use of energy storage assets. This software innovation represents a key mechanism for maximizing the value of "hardware" investments in energy storage technologies and is increasingly attracting the attention of regulators, investors, and governments.

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