Net-zero power

Long duration energy storage for a renewable grid

LDES
LONG DURATION ENERGY STORAGE COUNCIL

McKinsey & Company

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Whilst the contents of the report and its abstract implications for the industry generally can be discussed once they have been prepared, individual strategies remain proprietary, confidential and the responsibility of each participant. Participants are reminded that, as part of the invariable practice of the LDES Council and the EU competition law obligations to which membership activities are subject, such strategic and confidential information must not be shared or coordinated – including as part of this report.

Contents

Acronyms

BoP	Balance of plant
Capex	Capital expenditure
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CAES	Compressed air energy storage
CSP	Concentrated solar power
EV	Electric vehicle
Gt CO_2eq	Gigatonnes of carbon dioxide equivalent
GW	Gigawatt
GWh	Gigawatt-hour
GHG	Greenhouse gas
IEA	International Energy Agency
IRR	Internal rate of return
IPCC	Intergovernmental Panel on Climate Change
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized cost of electricity
LCOS	Levelized cost of storage
Li-ion	Lithium-ion
LAES	Liquid air energy storage
LDES	Long duration energy storage
MEDC	More economically developed countries
MPM	McKinsey Power Model
MW	Megawatt
MWh	Megawatt-hour
NDC	Nationally determined contributions
NPV	Net present value
NMC	Nickel, Manganese and Cobalt
O&M	Operation and maintenance
PV	Photovoltaic
PPA	Power purchasing agreements
PSH	Pumped storage hydropower
RE	Renewable energy
R&D	Research and development
RTE	Round-trip efficiency
TW	Terawatt
TWh	Terawatt-hour
TAM	Total addressable market
T&D	Transmission and distribution
WACC	Weighted average cost of capital

About the Long Duration Energy Storage (LDES) Council

The LDES Council is a global, CEO-led organization that strives to accelerate decarbonization of the energy system at lowest cost to society by driving innovation and deployment of long duration energy storage. Launched at COP26, the LDES Council provides fact-based guidance to governments and industry, drawing from the experience of its members, which include leading energy companies, technology providers, investors, and end-users.

With this first report the Council has focused on the role of LDES solutions in electrical power systems. In the future, the LDES Council will provide further insights into the LDES asset class, power and energy systems and the broader energy transition. The Council will also proactively engage with other parties on ways to accelerate decarbonization of energy systems in line with the Paris agreement.

The following organizations have announced the intention of forming the Council and are open to receive expressions of interest from additional founding members ahead of the official launch in early 2022 (Exhibit 1).

The report has been prepared by the members of the LDES Council in collaboration with McKinsey & Company as knowledge partner.

Exhibit 1

LDES council members

Technology providers

Highview Power, Azelio, Form energy, EnergyDome (Ground-breaking energy storage), Quidnet Energy, Enlighten, Ceres, e-zinc, Eos, Stiesdal, ESS Inc, Malta, Echogen power systems, Cellcube, Ambri, Redflow (sustainable energy storage)

Anchors

Industry and services customers

Rio Tinto

Low-carbon energy system integrators & developers

bp, Greenko, NEOM نيوم

Capital providers

Breakthrough Energy

Equipment manufacturers

Alfa Laval, Siemens Energy, Baker Hughes

Preface

As the world considers how to establish a path towards limiting the rise in global temperatures by curbing emissions of greenhouse gases (GHG), it is widely recognised that the power generation sector has a central role to play. Responsible for one third of total emissions, it is in fact doubly crucial, since decarbonizing the rest of the economy depends vitally on growing demand for renewable energy, for example in electric vehicles and residential heating. And the good news is that the global power industry is making giant strides towards reducing emissions by switching from fossil-fired generation to wind and solar power.

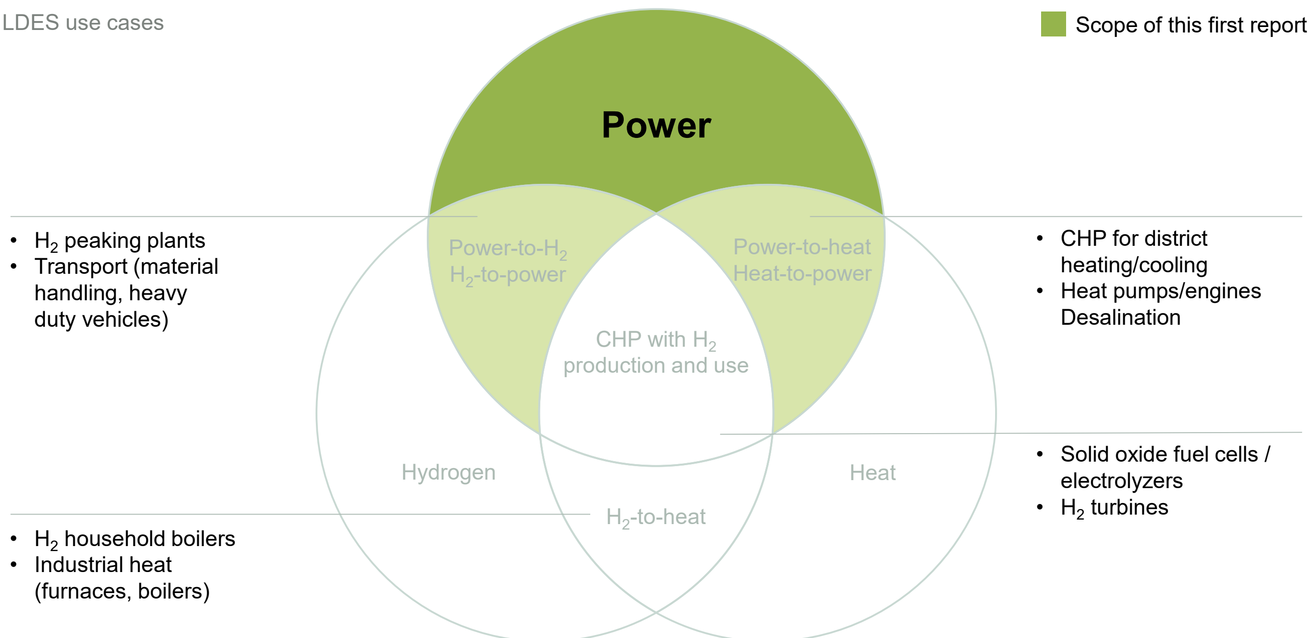
However, the rising share of renewables in the power mix brings with it new challenges. Not least of these are the structural strains on existing power generation infrastructure created by new flows of electricity and by the inherent variability of wind and solar power. This first report from the LDES Council aims to explore one of the key solutions to this challenge: long-duration energy storage (LDES).

LDES is defined as any technology that can be deployed competitively to store energy for prolonged periods and that can be scaled up economically to sustain electricity provision, for multiple hours, days, or even weeks, and has the potential to significantly contribute to the decarbonization of the economy. Energy storage can be achieved through very different approaches, including mechanical, thermal, electrochemical, or chemical storage (see Box 1).

The provision of flexibility, defined as the ability to absorb and manage fluctuations in demand and supply by storing energy at times of surplus and releasing it when needed, is a critical

Exhibit 2

LDES play a central role in energy system flexibility



enabling factor to decarbonize the economy in a cost-efficient way. Across the portfolio of technologies, LDES can provide flexibility in the energy system as a whole, comprising power, heat, hydrogen and other forms of energy (Exhibit 2). For example, some LDES technologies can discharge both heat and power (i.e., power-to-heat or heat-to-power) that can be used to decarbonize industries, or can use power to produce hydrogen via electrolysis, which can be reconverted back to power at a later time. The ability to integrate different sectors makes some of the technologies unique, and strengthens the business cases for their use in decarbonizing industries where the transition is a challenge.

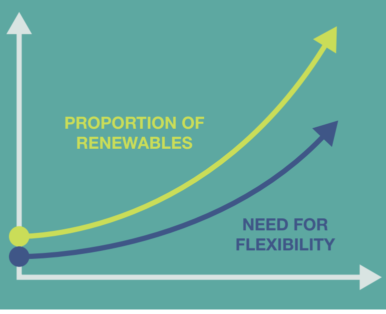
LDES technologies are attracting unprecedented interest from governments, utilities, and transmission operators, and investment in the sector is rising fast. This report focuses on the role of novel LDES solutions in electrical power systems (please refer to Box 1 for more details on the LDES technologies covered in this report). It first examines the characteristics of the technologies and how they may be suited to help manage structural issues in the power industry. It then considers LDES costs, how they may develop as the industry matures, and how they compare with those of other technologies that can be used to manage supply and demand such as Lithium-ion (Li-ion) batteries and hydrogen. Finally, it proposes some actions policy makers and industry players can consider to enable LDES to fulfil its potential as part of the world's net-zero solution.

What is the issue?

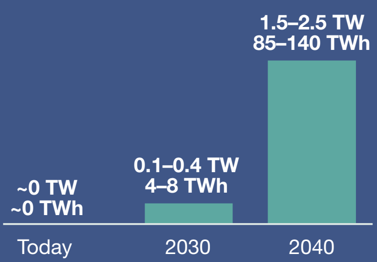
To avoid catastrophic climate change, we need to rapidly build a net-zero power sector predominantly powered by renewable energy.

As the proportion of renewables grows, we are presented with 3 challenges; balancing electricity supply and demand; a change in transmission flow patterns; and a decrease in system stability.

LDES can help address these issues by increasing the flexibility of the power system.



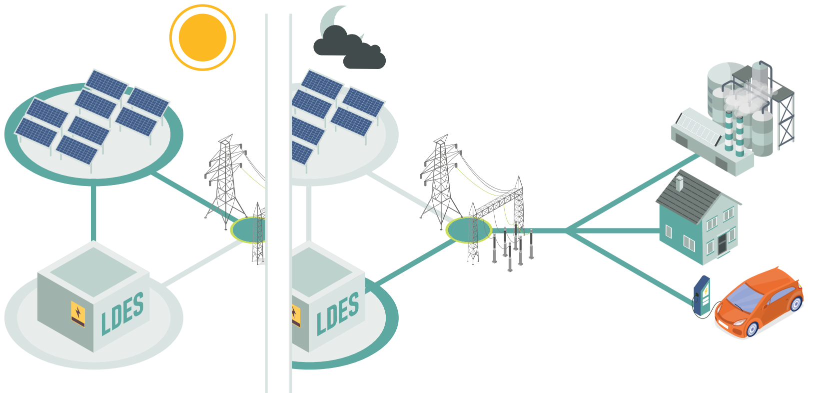
Projected installed capacity



How do LDES technologies help?

LDES are a host of different technologies that store and release energy through mechanical, thermal, electrochemical, or chemical means.

Alongside Li-ion battery technology and hydrogen, LDES technologies can play a critical and distinctive role in delivering flexibility on times **ranging from hours to weeks.**



Where are we today and where do we need to get to?

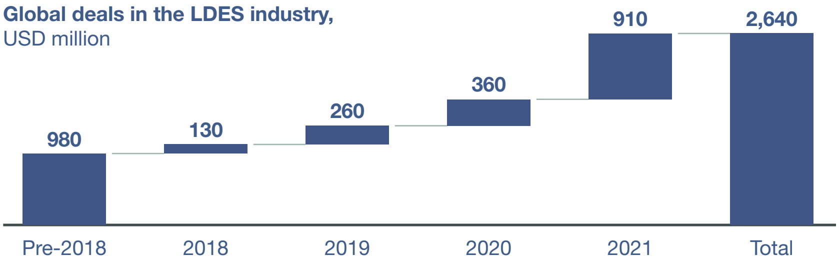
Many LDES technologies currently exist, but they are at different levels of maturity. Some have been deployed commercially, some are still at the pilot phase.

Our projections show that LDES need to be scaled up dramatically over the **next 20 years** to build a cost-optimal net-zero energy system.

By 2040, LDES need to have scaled up to **~400x present day** levels to **1.5–2.5 TW (85–140 TWh). 10%** of all electricity generated would be stored in LDES at some point.

Present-day LDES deployment is low, but momentum in LDES is growing exponentially.

Global deals in the LDES industry, USD million



How can we make this happen?

For LDES to be cost optimal, costs must **decrease by 60%.** However, even greater cost reductions have already occurred in other clean technologies like solar and wind.

Between 2022–40, USD 1.5 tr–3.0 tr of total investment in LDES will be required. The total investment over this period is comparable to what is invested in transmission and distribution networks **every 2–4 years.**

This investment has the potential to create economic and environmental benefit. The business cases for LDES can often be positive if sufficient mechanisms are in place to monetize the value.

The value of LDES can be unlocked through regulation change:

- Long-term system planning
- Support for first deployment and scaling up
- Market creation

Executive summary

The world is not on track to limit the rise in global temperature to 1.5° Celsius. To achieve the commitments made in the Paris Agreement, significant efforts must be made to reduce emissions across all sectors. The power sector, which accounts for roughly one-third of global emissions, will be central to global decarbonization, with many suggesting that it will need to achieve net-zero emissions by 2040. As a result, innovative solutions will be essential to meet three critical challenges for the power sector: tripling the amount of electricity produced to meet rising consumption, transforming the power system from fossil-powered generation to renewables, and meeting the social and economic cost of the transition.

Based on more than 10,000 cost and performance data points, this study shows that Long Duration Energy Storage technologies (LDES) can play a crucial role in helping create the system flexibility and stability required by an increasing renewable share in power generation, alongside other technologies such as Lithium-ion (Li-ion) batteries and hydrogen turbines.

LDES encompasses a range of technologies that can store electrical energy in various forms for prolonged periods at a competitive cost and at scale. These technologies can then discharge electrical energy when needed—over hours, days, or even weeks—to fulfill long-duration system flexibility needs beyond short-duration solutions such as Li-ion batteries. The various LDES technologies are at different levels of maturity and market readiness. This report focuses on the relatively nascent mechanical, thermal, chemical, and electrochemical storage technologies, instead of Li-ion batteries, dispatchable hydrogen assets, and large-scale aboveground pumped storage hydropower (PSH) (more details about LDES technologies are provided in Box 1).

The rapid integration of large RE capacities with their inherent variability creates large challenges for the power system, including potential imbalances in supply and demand, changes in transmission flow patterns, and the potential for greater system instability as the built-in inertia provided by fossil generation is removed. All of these call for new solutions to create flexibility in electricity supply and demand over different durations — intraday, multiday/multiweek, and seasonal.

LDES is one of these solutions, since LDES technologies entail low marginal costs for storing electricity: they enable decoupling of the quantity of electricity stored and the speed with which it is taken in or released; they are widely deployable and scalable; and they have relatively low lead times compared to upgrading of transmission and distribution (T&D) grids. As a result, there is increasing investment interest in these technologies, with more than 5 gigawatts (GW) and 65 gigawatt-hours (GWh) of LDES announced or already operational.

This is only a start: modeling suggests that LDES has the potential to deploy 1.5 to 2.5 terawatts (TW) power capacity—or 8 to 15 times the total storage capacity deployed today—globally by 2040. Likewise, it could deploy 85 to 140 terawatt-hours (TWh) of energy capacity by 2040 and store up to 10 percent of all electricity consumed. This corresponds to a cumulative investment of USD 1.5 trillion to USD 3 trillion and to potential value creation of USD 1.3 trillion by 2040.

The scale of these numbers reflects the multiple use cases for LDES technologies and the central role they can play in balancing the power system and making it more efficient. These include support for system stability, firming corporate power purchase agreements (PPAs) and optimisation of energy for industries with remote or unreliable grids. Similarly, there is a lot of potential in using LDES in off-grid systems, which have a lower level of flexibility and currently rely heavily on fossil fuels. But by far the largest proportion of deployment is expected to be related to the central tasks of energy shifting, capacity provision, and T&D optimization in bulk power systems.

In sum, LDES offers a lower-cost flexibility solution in many—but not all—situations. A diversified suite of solutions is likely to be deployed in order to achieve a cost-optimal decarbonization of the grid by 2040. The prize of deploying LDES at scale, however, is great. It is estimated that by 2040, LDES deployment could result in the avoidance of 1.5 to 2.3 gigatonnes of carbon dioxide equivalent (Gt CO_2eq) per year, or around 10 to 15 percent of today's power sector emissions. In the US alone, LDES could reduce the overall cost of achieving a fully decarbonized power system by around USD 35 billion annually by 2040.

Achieving this order of scale requires significant reductions in the cost of LDES technologies. But projections provided by LDES Council member companies show these are achievable and in line with learning curves experienced in other nascent energy technologies in the recent past, including solar photovoltaic and wind power. In turn, cost reductions will be dependent on improvements in research and development (R&D), volumes, and scale efficiencies in manufacturing. Similarly, total LDES deployment is closely tied to the rate of decarbonization of the power sector and the deployment of variable renewable energy (RE) generation.

While LDES technologies are still nascent, deployment could accelerate rapidly in the next few years. Modeling projects installation of 30 to 40 GW power capacity and 1 TWh energy capacity being installed by 2025 under a fast decarbonization scenario. A key milestone for LDES is reached when RE reaches 60 to 70 percent market share in bulk power systems, which countries with high climate ambitions aim to reach between 2025 and 2035. This catalyzes widespread deployment of LDES as the lowest-cost flexibility solution.

Before these targets are reached, however, government action will be required to help lower costs, mobilize the necessary investment and create market signals enabling investors to make an attractive return on LDES. An enabling governmental ecosystem would include the implementation of (i) long-term system planning, (ii) early compensation mechanisms that reduce uncertainty for investors while the market is still nascent, and (iii) supportive policies, regulations, and market designs.

Long-term system planning, including clear RE targets, is critical to creating investor confidence. Targeted support for early deployments and scale-up would help kick-start the market and trigger the learning curve on costs. Finally, supportive market designs such as capacity mechanisms and policies that capture the full value of LDES would enable investors to monetize their outlays. Together, these measures will ultimately help ensure that the energy transition is achieved at the lowest societal cost.

Box 1.

LDES technology space of this report

The term LDES is used to encompass a wide technology family with various levels of technological maturity and market readiness. While this class does not exclude Lithium-ion (Li-ion), hydrogen turbines, or large-scale, aboveground pumped storage hydropower (PSH), this report focuses on novel technologies that can fulfill the flexibility space beyond Li-ion batteries and other short-duration solutions. These technologies are herein referred to as "LDES", and do not include hydrogen, Li-ion, or large-scale aboveground PSH.

Novel LDES can be broadly classified into: mechanical, thermal, electrochemical, and chemical storage. (Exhibit 3)

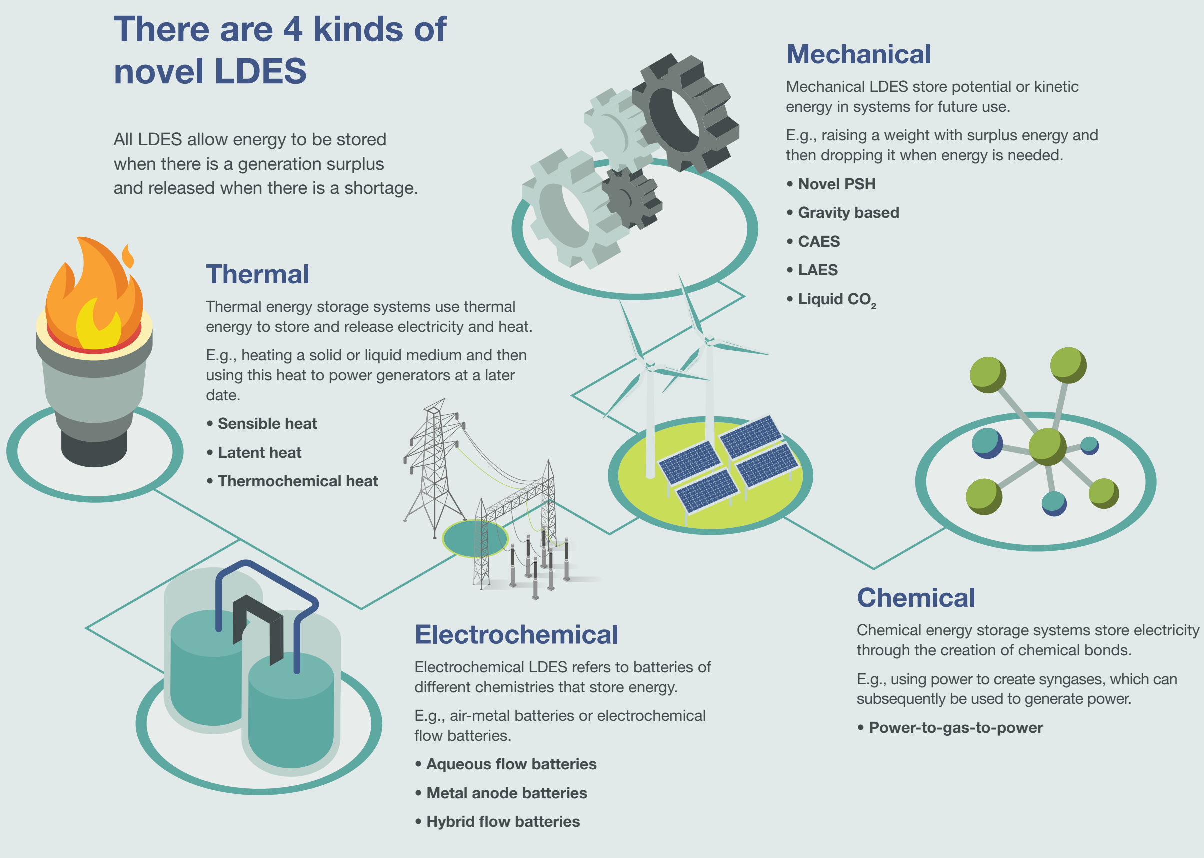
A. Mechanical LDES

The most widespread and mature storage technology is PSH, a form of mechanical storage that accounts for 95 percent of the total energy storage capacity worldwide. New versions of this established technology are emerging to reduce its dependence on geographical conditions, for example, geomechanical pumped hydro, which uses the same principles as aboveground PSH but with subsurface water reservoirs.

Other emerging mechanical energy storage solutions include compressed air energy

Exhibit 3

Overview of LDES categories



storage (CAES) and gravity-based energy storage. The first stores energy as compressed air in pressure-regulated structures (either underground or aboveground). In its adiabatic form, CAES also includes thermal storage to store the heat that is generated during compression and reuse it in the discharge cycle. Gravity-based energy storage is another promising form of mechanical storage, which stores energy by lifting mass that is released when energy is needed. This technology is in an earlier stage of commercial development.

Lastly, mechanical LDES can also take the form of liquid CO_2, which can be stored at high pressure and ambient temperature and then released in a turbine in a closed loop without emissions.

Liquid air energy storage (LAES) works similarly to CAES by compressing air but uses electricity to cool and liquify the medium and store it in cryogenic storage tanks at low pressure. For this reason, LAES is sometimes classified as mechanical storage and sometimes as thermal storage.

B. Thermal LDES

Thermal energy storage technologies store electricity or heat in the form of thermal energy. In the discharge cycle the heat is transferred to a fluid, which is then used to power a heat engine and discharge the electricity back to the system. Depending on the principle used to store the heat, thermal energy storage can be classified into sensible heat (increasing the temperature of a solid or liquid medium), latent heat (changing the phase of a material), or thermochemical heat (underpinning endothermic and exothermic reactions). These technologies use different mediums to store the heat such as molten salts, concrete, aluminum alloy, or rock material in insulated containers. Likewise, the charging equipment options are diverse, including resistance heaters, heat engines, or high temperature heat pumps among others.

The most widespread thermal LDES technology are molten salts coupled with concentrated solar power (CSP) plants, however, this technology is different from other novel LDES as it presents different characteristics (e.g. it cannot be widely deployed as it is not modular, the CSP plant has a large footprint and is only effective in regions with high solar radiation). Nonetheless, molten salts can effectively be used in novel thermal LDES to store electricity independently of CSP plants.

Thermal LDES technologies can discharge both electricity and heat, supporting the decarbonization of the heat sector, which accounts for around 50 percent of the global final energy consumption (compared to 20 percent by the electricity sector in 2019). Of the total heat consumption, it is estimated that only around 10 percent is supplied by RE.[1] LDES could support the decarbonization of this sector through the provision of zero-emissions high-grade heat to energy-intensive industries—that rely on fossil fuels and have few decarbonization alternatives—and other heat applications (such as district heating networks).

C. Chemical LDES

Chemical energy storage systems store electricity through the creation of chemical bonds. The two most popular emerging technologies are based on power-to-gas concepts: power-to-hydrogen-to-power, and power-to-syngas (synthetic gas)-to-power.

In the first case, electricity is used to power electrolyzers, which produce hydrogen molecules that can be stored in tanks, caverns, or pipelines. The energy is discharged when the hydrogen is supplied to a hydrogen turbine or fuel cell. If the hydrogen is combined with CO_2 in a second step to make methane, the resulting

1 "Renewables 2020," IEA, 2020.

gas—known as syngas—has similar properties to natural gas and can be stored and later burned in conventional power plants. Similarly, hydrogen can be converted to ammonia for direct combustion.

D. Electrochemical LDES

Different batteries of varying chemistries are emerging to provide long duration flexibility.

Electrochemical flow batteries store electricity in two chemical solutions that are stored in external tanks and pushed through a stack of electrochemical cells, where charge and discharge processes take place thanks to a selective membrane. These batteries are suited for long-duration applications where low chemical and equipment costs are possible.

Emerging metal air batteries rely on low-cost, abundant earth metals, water, and air – meaning they have the potential for high scalability and low installed system costs. Furthermore, many of these solutions do not suffer from thermal runaway, making them safe to install and operate.

There are also hybrid flow batteries with liquid electrolytes and a metal anode which combine some of the properties of conventional flow batteries and metal-anode systems.

Li-ion, hydrogen turbines, and large-scale aboveground PSH

This report distinguishes between LDES and Li-ion as the scaling up of costs for a long-duration flexibility range makes Li-ion uncompetitive for a long-duration flexibility range.

Hydrogen-based storage and reconversion to power via turbines (and fuel cells) can serve a role for long-duration storage but are called out separately in the report due to dissimilar cost performance at lower storage durations[2] and the specific interest that has evolved around hydrogen in the energy community.

Large-scale aboveground PSH are not included in the considered technology space as the deployment benefits and economics of novel LDES technologies, including novel PSH, are expected to outcompete these plants and LDES have fewer geographical limitations.

[2] Where a hydrogen technology demonstrates very similar behaviors and cost profiles to other LDES it has been included (such as solid oxide fuel cells).

Data collection and benchmarking

The data used in the analysis of this report was collected from the LDES Council members, who submitted a total of more than 10,000 data points outlining the cost and performance of their technology. The data was aggregated and processed by an independent third-party clean team.

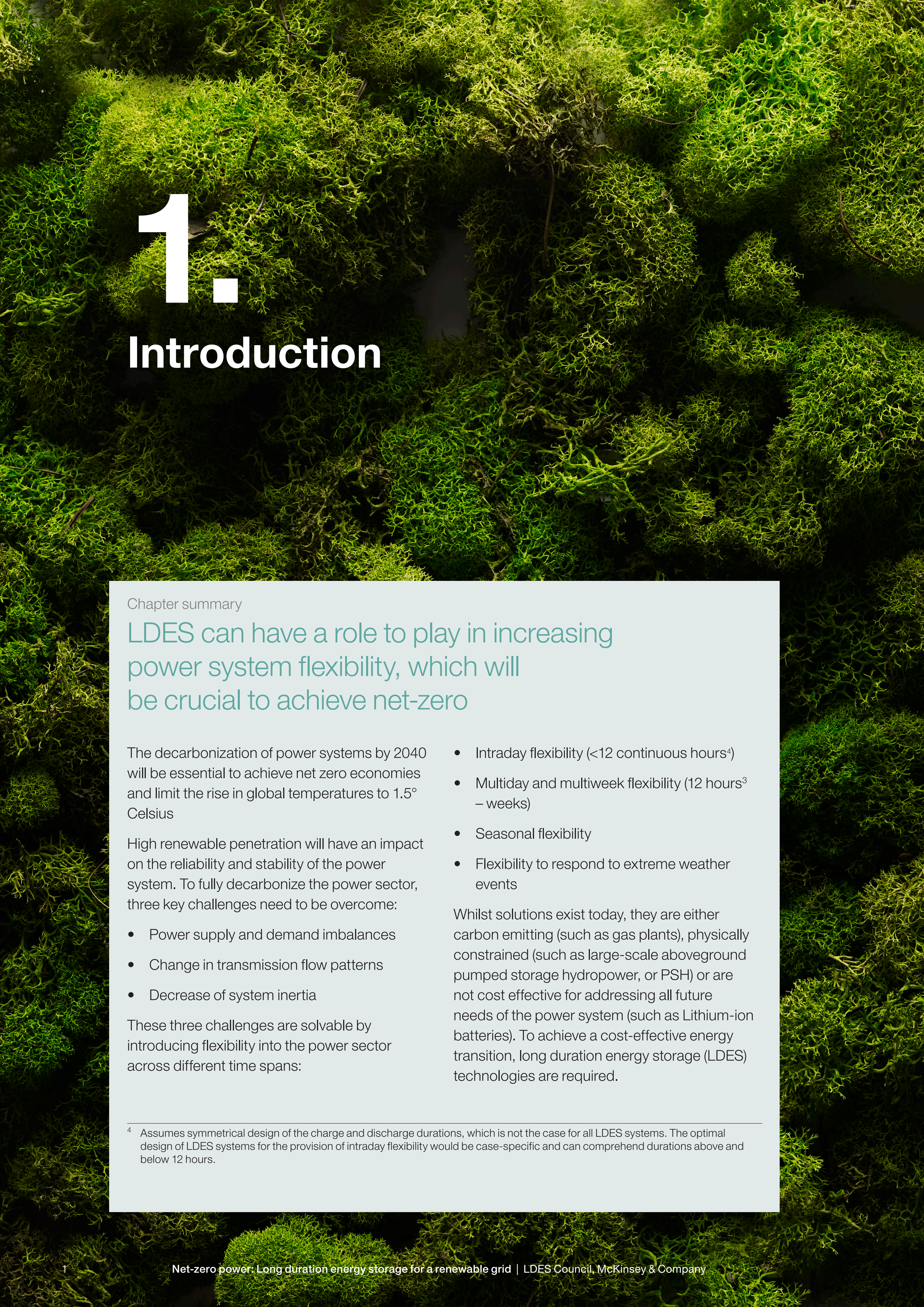
Council members provided cost and performance data for two projected trajectories for how these metrics would change from a "progressive" to a "central" scenario:

- Progressive scenario: council data reflecting ambitious cost-reduction trajectories and learning rates
- Central scenario: council data reflecting conservative cost-reduction trajectories and learning rates

The data was grouped into two archetypes based on their nominal duration: 8 to 24 hours[3] and 24 hours or more, with some members offering products in both ranges. For every archetype, aggregated data points for each cost, design, or performance metric created representative numbers while preserving the data confidentiality of each individual technology. After the data point aggregation, top-quartile and median figures were processed, yielding eight finalized data sets: first quartile and median, for 8 to 24 hours and 24 hours or more in central and progressive scenarios. The created archetypes were used as inputs to model the total addressable market (TAM) and to generate insights on cost competitiveness with alternative technologies presented in this report. Future iterations of the analysis aim to incorporate more data points per technology type, allowing for a disaggregate analysis for each LDES category (mechanical, thermal, electrochemical, and chemical) and duration archetype.

The technology benchmarking in the report builds on the McKinsey Power Model (MPM), McKinsey Battery Cost Model, McKinsey Energy Insights modeling of RE costs and capacity factors, other proprietary assets, and numerous benchmarks from external data providers and databases. The analytics team also tested the findings from these analyses with experts outside the Council and with individual Council members, who provided industry expertise.

[3] The 8-hour threshold does not imply that LDES is not expected to provide services below this duration.



1. Introduction

Chapter summary

LDES can have a role to play in increasing power system flexibility, which will be crucial to achieve net-zero

The decarbonization of power systems by 2040 will be essential to achieve net zero economies and limit the rise in global temperatures to 1.5° Celsius

High renewable penetration will have an impact on the reliability and stability of the power system. To fully decarbonize the power sector, three key challenges need to be overcome:

- Power supply and demand imbalances
- Change in transmission flow patterns
- Decrease of system inertia

These three challenges are solvable by introducing flexibility into the power sector across different time spans:

- Intraday flexibility (<12 continuous hours[4])
- Multiday and multiweek flexibility (12 hours[3] – weeks)
- Seasonal flexibility
- Flexibility to respond to extreme weather events

Whilst solutions exist today, they are either carbon emitting (such as gas plants), physically constrained (such as large-scale aboveground pumped storage hydropower, or PSH) or are not cost effective for addressing all future needs of the power system (such as Lithium-ion batteries). To achieve a cost-effective energy transition, long duration energy storage (LDES) technologies are required.

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[4] Assumes symmetrical design of the charge and discharge durations, which is not the case for all LDES systems. The optimal design of LDES systems for the provision of intraday flexibility would be case-specific and can comprehend durations above and below 12 hours.

The decarbonization of power systems by 2040 will be essential to achieve net-zero economies and limit the rise in global temperatures to 1.5° Celsius

Accounting for roughly 80 percent of global GDP, 123 countries have pledged to achieve net-zero greenhouse gas (GHG) emissions and/or carbon neutrality by 2050.[5] However, current efforts are insufficient to achieve such targets and move the world onto the 1.5° pathway set out in the Paris Agreement. Human activity has already led to a rise in global temperatures.[6] Economies are not on track to reduce their emissions rate, which is rising again after a brief dip caused by the Covid-19 pandemic and is expected to rise further in the coming years. As a result there is a growing risk of severe climate change in the coming years and decades with convulsive environmental and socioeconomic consequences.

To meet climate targets and limit the impact of climate change, immediate action is required. An ambitious combination of solutions is needed to achieve the necessary GHG emission reductions, including aggressive decarbonization rates and systemic changes in energy supply across all sectors.[7]

The power sector is among the largest emitters of GHGs, and its decarbonization is crucial to establishing the pathway towards a net-zero economy by 2050. Electricity generation worldwide was responsible for emissions of 12.3 gigatonnes of carbon dioxide equivalent (Gt CO_2eq) in 2020,[8] around a third of total emissions. Demand for electric power is growing, driven by increased electrification across multiple end uses, for example, by electric vehicles (EVs) and residential heating. New sources of demand are linked to the integration of energy-consuming and supply sectors (what is known as “sector coupling”), increased population, and higher living standards in emerging markets and developing economies. In a deep decarbonization scenario, widespread electrification could cause power consumption to triple by 2050.[9]

To reach a 1.5° Celsius decarbonization pathway, this study assumes that the global power sector will need to achieve net-zero emissions by 2040 (Exhibit 4). To achieve such a target, it is assumed that more economically developed countries (MEDCs) achieve net-zero emissions by 2035 and the rest of the world by 2040. This milestone is consistent with the most recent net-zero report from the International Energy Agency (IEA).

The enabling low-carbon power-generation technologies are already available at scale. In many instances, they can be deployed at a lower cost of generation than thermal sources, allowing the power sector—including large, interconnected networks, isolated grids, and mini-grids—to decarbonize ahead of other sectors.

Power systems will have to rapidly accommodate large amounts of renewable energy (RE), which will pose new system challenges

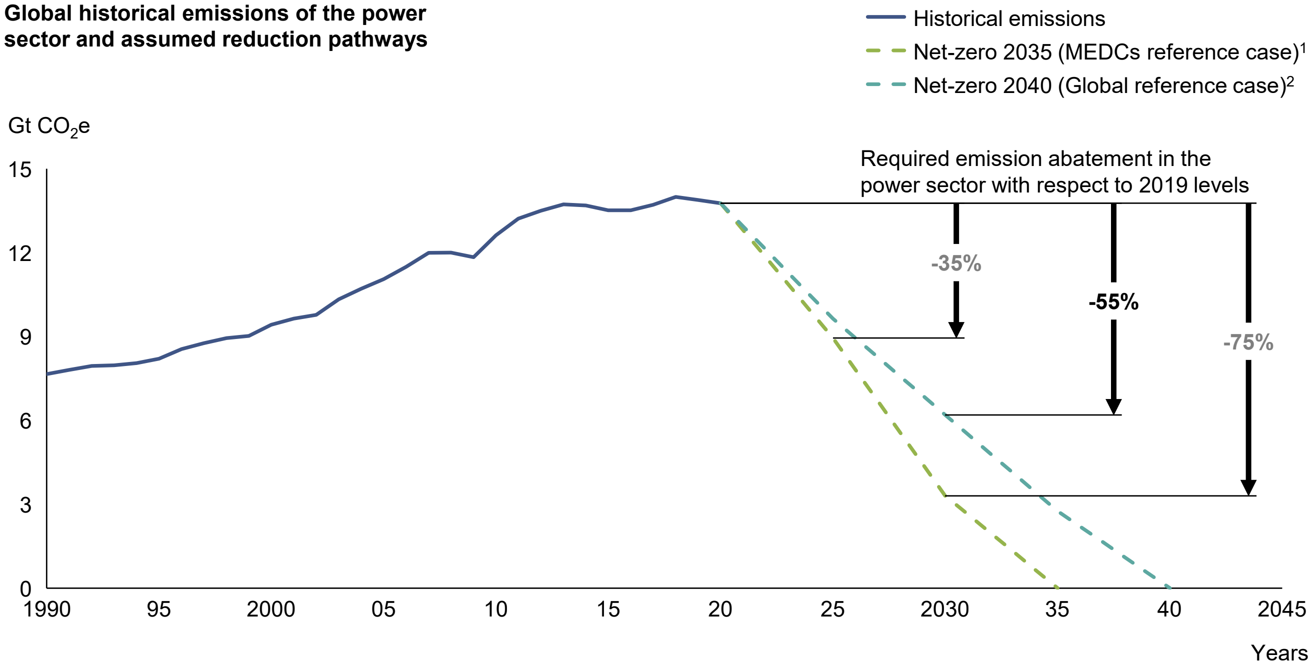
To limit carbon emissions, power generation will have to accelerate its transition to RE. The falling LCOEs (levelized cost of electricity) of RE are already accelerating the adoption of wind and solar as existing plants retire, and power demand grows—even in the absence of policy support. If governments adopt strong policies and create appropriate market designs, the transition could be accelerated. While negative carbon emissions solutions will be critical to achieving full decarbonization of economies, their impact by 2040 will be limited and largely influenced by tailwinds supporting their scale-up, including the availability of appropriate carbon dioxide (CO_2) transportation and storage infrastructure and social acceptability.

The rapid integration of large RE capacities in the system—with estimated annual wind and solar photovoltaic (PV) capacity additions of more than 1 terawatts (TW) by 2030 in the electricity sector alone[10]—entails some challenges for system planners and market players alike, calling for new solutions that help accommodate increased

5 Net Zero tracker, accessed on 29 October 2021.
6 NASA Goddard Institute for Space Studies.
7 “Climate change 2021: the physical science basis,” IPCC, 2021.
8 “Net zero by 2050, a roadmap for the global energy sector,” IEA, 2021.
9 “Climate math: what a 1.5-degree pathway would take,” McKinsey & Company, 2020.
10 “Net zero by 2050, a roadmap for the global energy sector,” IEA, 2021.

Exhibit 4

Power sector emission reduction pathways



Key assumptions

1. Informed by IEA Net Zero 2050 report on more economically developed countries (MEDCs) needs to get to net zero power by 2035. Consistent with US President Biden climate ambition.
2. Informed by IEA Net Zero 2050 report on the world's power sector needs to get to net zero by 2040.

amounts of renewable power. (Exhibit 5)

Power supply and demand imbalances

By definition, the addition of renewables to the electricity mix creates imbalances in supply and demand, since the natural fluctuations in wind and solar PV power do not match fluctuations in power demand. Increased shares of geographically concentrated wind and solar power in the generation mix will thus lead to more frequent periods of power surplus and shortage. In the case of prolonged periods without sufficient sun or wind, these imbalance periods may last days or even weeks. As a result, and as RE becomes more common, the grid will need to become more flexible to develop the capacity to maintain the supply-and-demand balance while incentivizing RE deployment.

Compounding the challenge, the higher frequency of extreme weather events caused by climate change, such as heat waves and heavy precipitation, will also create more strain on a grid dominated by RE generation. For instance, according to the latest Assessment Report by the United Nations Intergovernmental Panel on Climate Change (IPCC), flooding and extreme precipitation are projected to increase at global warming levels exceeding 1.5° Celsius in nearly all regions. Similarly, the frequency, duration, and intensity of hot extremes are very likely to increase.[11] In this context, power systems will need to be resilient to prolonged supply disruptions and ensure sufficient firm capacity to guarantee the security of supply in extreme weather events.

Change in transmission flow patterns

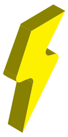
Power systems will also see a shift in the geographical supply pattern, and an alteration of transmission line power flows. These changes result from the increased deployment of decentralized RE generation driven by technological developments and accelerated cost improvements (for example, in residential PV and behind-the-meter batteries). They will also reflect the geographical dependency of RE capacity, which will tend to be concentrated in areas with abundant supplies of sun and wind.

[11] "Climate change 2021: the physical science basis. Contribution of Working Group I to the sixth assessment report of the intergovernmental panel on climate change," IPCC, 2021.

Exhibit 5

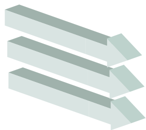
A net-zero power system cannot be built without also developing different types of system flexibility

Shifting to a power system that predominantly relies on renewable energy presents 3 key challenges …



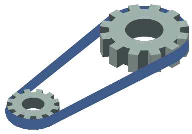
Power supply and demand imbalances

The supply of electricity from renewables does not always match the demand



Change in transmission flow patterns

Changes in the distribution of the energy system can require costly and lengthy developments to transmission lines



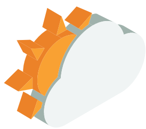
Decrease in system inertia

Removing conventional generators from the system also removes the inertia from rotating masses from the system

… to resolve these challenges, flexibility on different time scales is needed

Intraday flexibility

Flexibility that allows daily variations in supply and demand to be smoothed out (such as peak energy demand in the evening)



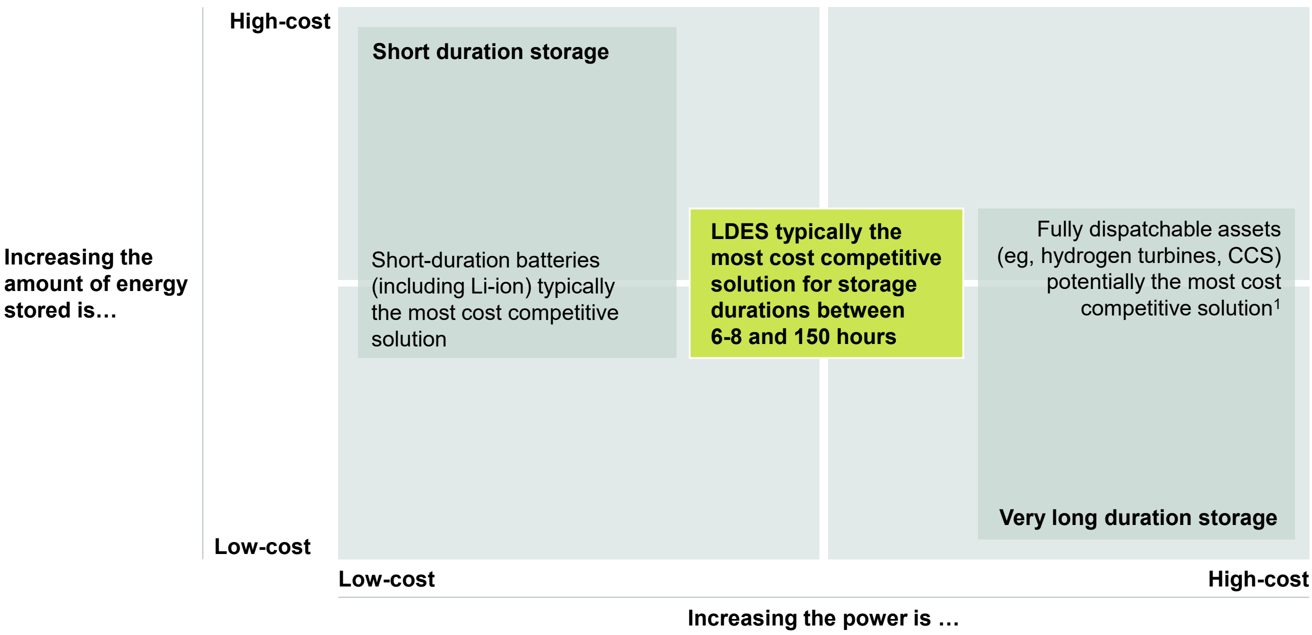
Multiday and multiweek flexibility

Flexibility that allows day to week long fluctuations in supply and demand to be balanced (such as taking into account weather anomalies)

Multi-month flexibility

Flexibility that allows seasonal mismatches in supply and demand to be managed (such as energy demand peaks in winter)

This gives LDES technologies an advantage providing electricity system flexibility between 8 and 150 hours in length



1. Technologies not mature yet (still in commercial demonstration) requiring cost reductions

Changes on the consumer side will switch the traditional one-way design of electricity lines to a two-way system, where an increased number of end users will generate their own electricity and inject it into the power grid.[12] This will pose challenges to the conventional distribution systems such as voltage control and stability. An example of this trend can be seen in California, where public incentives and governmental support have led to the deployment of more than 10 gigawatts (GW) of distributed solar generation (representing 10 percent of its total generation capacity mix) in the past ten years.[13]

Similarly, regions with high RE yield potential will likely become new generation centers that impact how networks operate. For example, one study showed that historical transmission flow patterns in New York State are likely to be reversed due to increased solar and offshore wind power injection. Flow directions will also vary over time as RE yield fluctuates throughout the day and year.[14] Long lead times and slow grid adaptation to these system changes could result in more frequent congestion, reducing the stability of the power system and jeopardizing its ability to meet decarbonization targets.

Decrease of system inertia

The stability of the system is also challenged as the bulk of power generation transitions from synchronous to asynchronous technologies. Conventional generators (for example, fossil fuels and nuclear) have played a crucial role in safeguarding the stability of the electricity system through their provision of inertia: in a system disturbance, the rotating machines connected to the grid help all generators remain synchronized by resisting a change in the frequency of the grid. If unrectified, stability faults can result in blackouts with high economic and societal costs.

By contrast, newer technologies like solar PV and wind lack rotating masses directly connected to the grid and therefore cannot provide inherent system inertia. As a result, generation disturbances, frequency, and voltage deviations necessitate the installation of new stability sources. Grid-forming inverters, which use power electronics to set the correct frequency ("artificial inertia") and synchronous condensers are current technological solutions.

A net-zero power system will need flexibility resources at different duration levels, where long duration energy storage (LDES) can play a crucial role

A broad range of flexibility levers and enablers already exist to help balance RE generation. Existing solutions include dispatchable capacity (for example, gas peakers, or generation plants that can be activated at times of peak electricity use, and pumped hydro), the expansion of transmission grids, including internal and cross-market interconnections, feed-in management and RE curtailment, as well as short-duration batteries.

However, these traditional approaches are not an adequate answer to the evolving needs of the system. The most widespread solution—gas peakers—emits carbon and requires deployment of carbon capture and storage (CCS). This increases its capital intensity and generally requires it to be installed close to a CO_2 storage formation. Grid expansion can reduce congestion risk but is costly, has long lead times, and is unsuitable in some population centers. Furthermore, constructing physical infrastructure to accommodate peak demands tends to have a low return on investment. Feed-in management and power curtailment are inherently inefficient, as they result in lost supply. Lastly, short-duration energy storage has technical and economic limitations that mean it cannot meet the full range of flexibility durations required.

As a result, new low-carbon flexibility sources are starting to emerge, including demand-side response mechanisms, hydrogen dispatchable plants, and LDES technologies. A diversified suite of solutions is likely to be deployed in order to achieve a cost-optimal decarbonization of the grid by 2040 (Exhibit 6).

Intraday flexibility

This covers the need for flexibility for durations below 12 continuous hours[15] and generally

[12] "Distributed energy resources for net zero: An asset or a hassle to the electricity grid?," IEA, 2021.
[13] California Distributed Generation Statistics.
[14] "The global relevance of New York State's clean-power targets," McKinsey & Company, 2019.
[15] Assumes symmetrical design of the charge and discharge durations, which is not the case for all LDES systems. The optimal design of LDES systems for the provision of intraday flexibility would be case-specific and can comprehend durations above and below 12 hours.

Exhibit 6

Summary of existing and emerging flexibility solutions for different flexibility duration needs

✓ Solution (✓) Partial solution

Flexibility duration	Power system challenge	Dispatchable generation	Grid rein-forcement	Curtailment or feed-in management	Li-ion batteries	LDES	Demand-side response
Intraday	Intermittent daily generation	✓		✓	✓	✓	✓
	Reduced grid stability	✓			✓	✓	(✓)
Multiday, multiweek	Multi-day imbalances	✓	(✓)	(✓)	(✓)	✓	
	Grid congestion	(✓)	✓	✓	(✓)	✓	
Seasonal duration	Seasonal unbalances	✓	✓			✓	
	Extreme weather events	✓				✓	

involves providing grid stability services and peak-shifting. Lithium-ion (Li-ion) batteries are currently the cheapest zero-emissions option for providing balancing services of less than 4 hours. In the 4- to 8-hour range, other technologies can also accommodate load cycles. These technologies include LDES, demand-side response mechanisms, power curtailment, and peaking assets. In this range, the cost of Li-ion four-hour systems is below USD 400 per kilowatt-hour (kWh) today, and forecasted to decrease to around USD 200 per kWh in the next 10 years. With increasing RE shares in the power mix, the need for 8-to-12-hour flexibility is projected to grow and become a significant market for LDES technologies.

Multiday and multiweek flexibility

This stretches from 12 hours[15] to periods lasting days or weeks. It is needed to address extended periods of imbalanced RE output or potential outages caused by transmission constraints. Traditionally, the system has relied on conventional power plants, electricity supply curtailment, and gradual transmission grid expansion. LDES technologies are a promising zero-carbon solution for these long-duration flexibility needs, especially those lasting several days.

Seasonal flexibility and extreme weather events

The need for seasonal flexibility arises from natural variability of solar irradiation, wind speed, temperature, and rainfall over weeks and months, and also from potential exposure to extreme weather events. Grid strengthening, RE oversizing and curtailment, dispatchable assets, including hydrogen and biogas with CCS, and natural gas with CCS, could fulfill the/se needs. LDES can as well, while also providing resilience in the face of extreme weather conditions.

The set of flexibility needs is likely to evolve following the transition of the power mix. In the short term, between now and 2030, as the share of RE remains limited, power systems will mainly require intraday flexibility. Nevertheless, there will be local specific applications with high RE shares and the consequent need for longer durations, even in the short term. Modeling suggest the adoption curve of longer flexibility durations accelerates at levels of RE penetration of 60 to 70 percent, which will likely be reached in many places over the next decade. To achieve global net-zero power by 2040, seasonal flexibility solutions are required to ensure decarbonization in regions with limited potential for a balanced RE portfolio and with limited regional transmission lines.

2.

LDES technologies characterization and current status

Chapter summary

LDES technologies can play a critical and unique role delivering flexibility on times ranging from hours to weeks

LDES technologies, like other forms of electricity storage, allow energy to be stored at times when energy supply exceeds demand and released at times when energy demand exceeds supply

Novel LDES technologies have distinctive features relative to other forms of electricity storage:

- The marginal costs of storing additional energy are low (i.e., each additional kWh of energy stored does not increase cost significantly)
- There is decoupling of the quantity of energy an LDES technology can store and the rate at which an LDES can uptake and release energy (i.e., LDES can create a very large store of energy with a small stream of energy)
- They are widely deployable and scalable as they have few geographical requirements, are modular and do not depend on rare-earth-elements
- They have relatively low lead-times compared to transmission and distribution (T&D) grid upgrade and expansion

Novel LDES technologies have been deployed today:

- Total investment in major LDES companies has reached more than USD 2.5 billion and has accelerated in the past years
- Excluding large-scale aboveground PSH, more than 5 GW and 65 gigawatt-hours (GWh) of LDES is already operational or has been announced. Nevertheless, the majority of these deployments are associated with traditional molten salts for concentrated solar power (CSP) and compressed air energy storage (CAES) technologies

LDES comprises several technologies, each operating on different storage or physical principles and with different architectures. As a result, it is challenging to provide a unified perspective of LDES performance characteristics. However, some features are inherent to LDES technologies and are crucial for transitioning to a clean grid. (Exhibit 7)

LDES technologies are characterized by a low energy storage capacity capex and by their ability to decouple power and energy capacities

LDES provide significant benefits in terms of optimal system sizing and scaling-up costs, including low energy storage capacity capital expenditure (capex) and decoupling capabilities. Bulk energy storage capacity can be scaled up at a low incremental cost while not affecting the charging and discharging cycle design; in other words, systems can be designed for long durations without the need for additional costly power capacity. As a result, these systems can provide power for long durations and generally do not need to stack services to recover the investment. This results in the low degradation of their storage capacity, and in the potential to reach very long life spans, of around 30 years, before requiring significant upgrades. Some LDES technologies also have very low capacity degradation even at high levels of operation.

Being as a modular solution, Li-ion batteries deliver rated power and energy as a bundle precluding the optimal independent scaling of power and energy capacities, and limiting their ability to provide long-duration services economically. These technologies can maintain output for prolonged periods by reducing discharge rates and derating discharge capacity (i.e., providing less than the rated power), which is a sub-optimal solution to achieving longer storage durations.

Importantly, the charging power of some LDES technologies can be designed independently of the discharging power, which highlights their versatility and adaptability to ecosystems with different supply and load profiles.[16] Some mechanical LDES, for example, are charged

Exhibit 7

LDES key concepts

Power and energy are the key features of LDES

Power capacity of LDES

The maximum electricity output that can be physically discharged by an LDES system in a given instant (a flow). It is measured in watts (W)

Energy capacity of LDES

The maximum amount of electricity the LDES system can store (an amount). It is measured in watts-hour (Wh)

In LDES technologies power and energy capacity is decoupled

Unlike other forms of electricity storage, LDES energy capacity can be scaled without scaling up power capacity …

… which makes it cheaper to increase the amount of electricity stored …

… without significantly compromising the power supply.

In addition to this, LDES technologies often also have other beneficial features

Projects typically have short lead times

Storage solutions are not geographically limited

Solutions don't depend on rare-earth-materials

[16] This is not the case for some electrochemical LDES storage technologies, which have symmetric power charging and discharging capacities.

by a compressor and discharged by a turbine, with each process designed independently and with different efficiencies. Moreover, the asymmetry opens up more possibilities for revenue optimization. For example, technology owners can optimize energy arbitrage by slowly charging overnight when power prices are low and discharging energy in a shorter amount of time when prices are high.

Additional operational and deployment benefits of some LDES technologies can add significant value to the system

LDES can offer additional operational and deployment advantages, such as shorter lead times than grid upgrades and expansion, and fewer large-scale deployment constraints. These advantages vary by technology, and some must still be demonstrated in pilots and commercial plants.

Shorter lead times than transmission and distribution (T&D) grid upgrades and expansion

Historically, the connection of new generation plants to constrained grids has been addressed by upgrading existing lines. Grid capacity expansion reduces congestion risk; however, it is a capital-intensive process that requires long-term planning. Furthermore, it is becoming increasingly difficult for operators as decentralized generation plans proliferate and as project connections become less certain. Moreover, the complexity and permitting requirements of transmission grid projects cause nearly 20 percent of all projects to be delayed or canceled.

LDES entails a cost-effective solution for transmission optimization, increasing grid utilization and virtual grid capacity while deferring grid upgrades. LDES technologies have average construction times of one year and less onerous permitting requirements than grid upgrades. Similarly, they can be applied to large corridors with multiple sites at capacity, allowing for the construction of new RE sites.

Widely deployable and scalable

Most emerging LDES technologies have few deployment restrictions (Exhibit 8). These systems, for example, do not have specific geographical requirements, such as dams in the case of traditional PSH, and have lower footprints per installed capacity. Depending on the specific technologies, some can be built underground or very close to populated areas due to their low safety risks.

In addition, many technologies have a modular architecture that allows initial deployment of systems at shorter durations or smaller power capacities that can be scaled up as the system evolves.

LDES can also repower or upsize existing plants, which will be increasingly relevant as the presence of RE sites grows. This would optimize land use and allow RE facilities to leverage grid connection permits. Additionally, some LDES technologies present opportunities for the reutilization of potentially stranded fossil assets. For example, gas storage fields can be used for compressed air energy storage (CAES) systems, or coal and gas plants can be converted into thermal storage plants. Thermal LDES solutions can provide additional flexibility by coupling the heat and power sectors and supporting the decarbonization of end uses that rely on fossil-based heat.

In terms of practicality, several LDES technologies rely on existing supply chains, most of which use earth-abundant materials available in large quantities globally, both in the core technology and the balance of plant (BoP) system. This safeguards against potential future supply chain shortages of certain Li-ion technologies, such as nickel, manganese and cobalt (NMC) batteries: more than 65 percent of global cobalt production concentrated in the Democratic Republic of the Congo.[17] However, this is not the case for all LDES equipment, as some use certain scarce metals (for example, vanadium) and electric motors or generators with rare-earth magnetic materials. While these products do not face supply constraints now, there is potential for scarcity in the future.

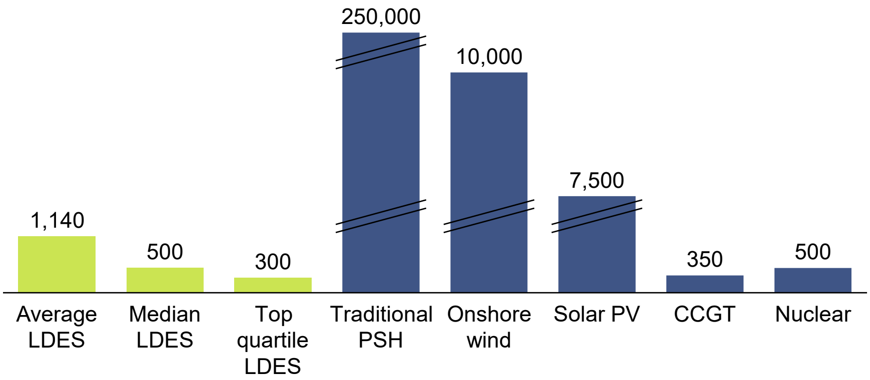
Specific characteristics of novel LDES technologies can be found in Box 2.

[17] "Lithium and cobalt – a tale of two commodities," McKinsey & Company, 2018.

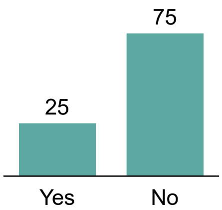
Exhibit 8

LDES Council technologies benchmarking for different deployment parameters

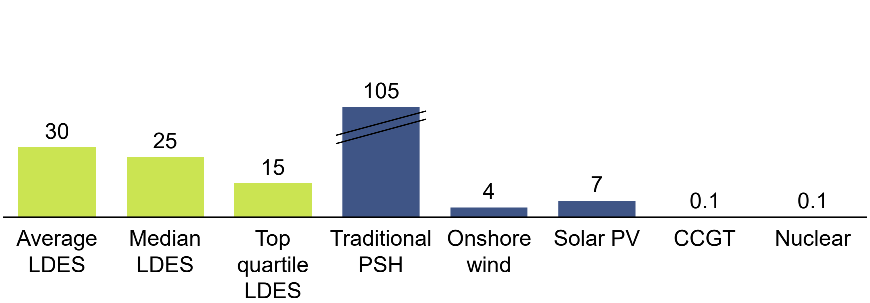
Unit footprint
m²/MW



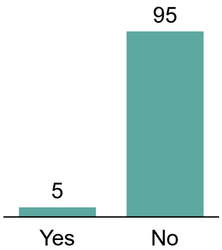
Companies with site constraints
%



Unit footprint
m²/MWh



LDES companies with some scarce material dependency[1]
%



1. Use of vanadium and magnetic materials for electric generators, not experiencing supply constraints now, but presenting potential scarcity issues.

Box 2.

Novel LDES technologies present very different characteristics, making them suitable for different applications

Exhibit 9

Key LDES storage types and parameters

Energy storage form	Technology	Market readiness	Max deployment size, MW	Max nominal duration, Hours	Average RTE[1] %
Mechanical	Novel pumped hydro (PSH)	Commercial	10–100	0–15	50–80
	Gravity-based	Pilot	20–1,000	0–15	70–90
	Compressed air (CAES)	Commercial	200–500	6–24	40–70
	Liquid air (LAES)	Pilot (commercial announced)	50–100	10–25	40–70
	Liquid CO_2	Pilot	10–500	4–24	70–80
Thermal	Sensible heat (eg, molten salts, rock material, concrete)	R&D/pilot	10–500	200	55–90
	Latent heat (eg, aluminum alloy)	Commercial	10–100	25–100	20–50
	Thermochemical heat (eg, zeolites, silica gel)	R&D	na	na	na
Chemical	Power-to-gas-(incl. hydrogen, syngas)-to-power	Pilot (commercial announced)	10–100	500–1,000	40–70
Electrochemical	Aqueous electrolyte flow batteries	Pilot/commercial	10–100	25–100	50–80
	Metal anode batteries	R&D/pilot	10–100	50–200	40–70
	Hybrid flow battery, with liquid electrolyte and metal anode	Commercial	>100	25–50	55–75

1. Power-to-power only. RTEs of systems discharging other forms of energies such as heat can be significantly higher.

Investor interest in LDES has increased in recent years, with more than USD 2.5 billion invested in LDES companies

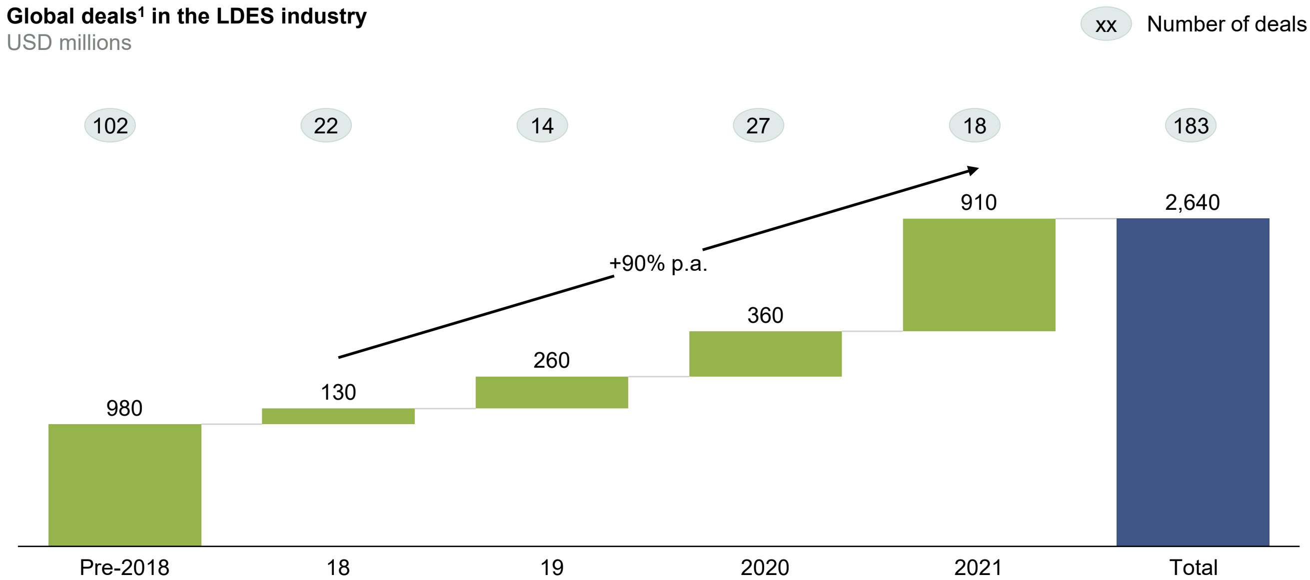
The potential of LDES technologies to increase the integration of low-cost wind and solar resources while reducing the cost of decarbonized power systems has prompted a surge of new commercial initiatives and research and development (R&D) efforts. Cumulative investment in major LDES companies exceeded USD 2.5 billion in 2021, having nearly tripled in the last four years (Exhibit 10).

More than 5 GW and 65 GWh of LDES is already operational or has been announced

Over 260 LDES projects have been announced worldwide at different commercial stages

Exhibit 10

Investment activity in LDES companies



1. Based on public investments, VC, PE, corporate, and debt investments of 25 major LDES companies.

(Exhibit 11).[18] These projects total 5 GW and 65 GWh, with roughly 230 projects and 75 percent of the capacity already contracted, under construction, or operational. This capacity does not include large-scale aboveground PSH projects, which represent more than 95 percent of all LDES capacity installed globally today (for more information on PSH refer to Box 3).

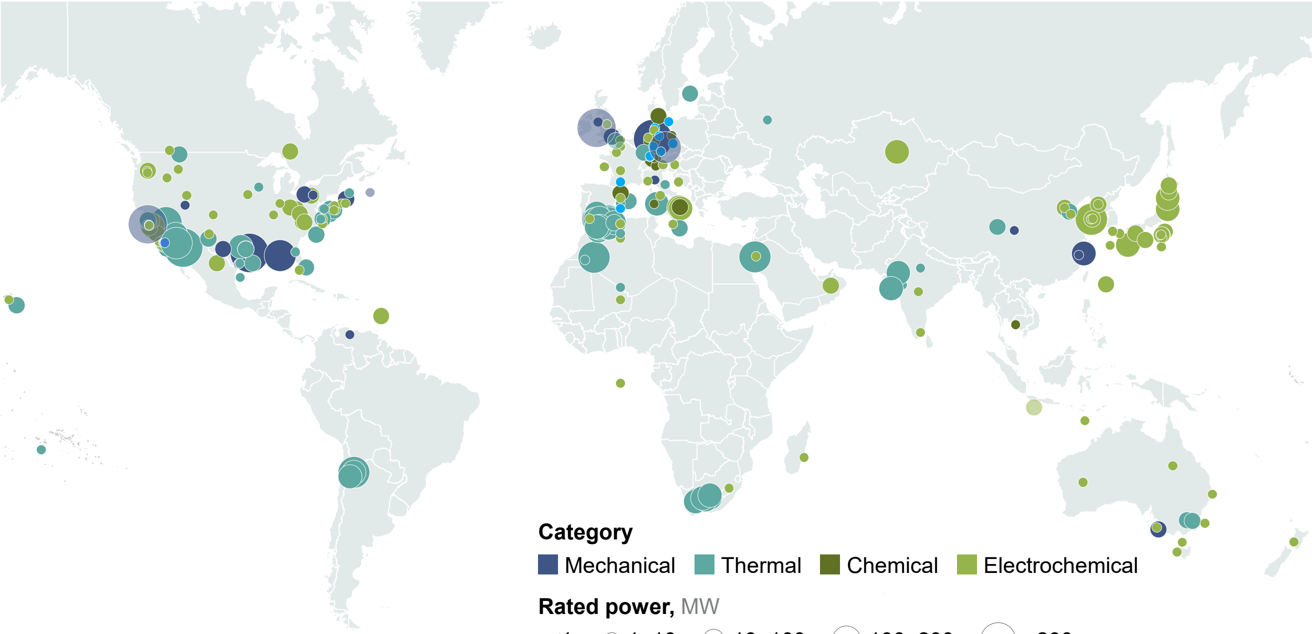
However, the majority of the capacity is associated with traditional molten salts and CAES technologies, which have some deployment limitations compared to novel LDES (such as their large footprint and limited modularity). Thermal LDES accounts for the largest share of the total announced capacity (60 percent), attributable primarily to a number of molten salt storage facilities for concentrated solar power (CSP) in the megawatt (MW) scale. Traditional CAES holds the second-largest capacity share (around 30 percent) and the largest average plant size (80 MW). Flow batteries account for the highest number of projects (over 100), but their average announced capacity is significantly lower at around 4 MW. This means that, while the potential of other LDES technologies is high, their widespread adoption is dependent on their commercial demonstration and cost developments.

The US, Spain, and Germany have the largest reported capacities and projects in terms of regions. The capacity in the US is balanced between mechanical, thermal, and electrochemical projects, accounting for roughly 30 percent of global capacity. Most LDES projects in Spain, which account for 20 percent of global announcements, are thermal LDES. Germany also has two CAES projects with more than 200 MW, accounting for 10 percent of the total announced capacity globally. In Asia, Japan and China have announced at least 30 electrochemical projects, combining both flow and metal anode batteries.

[18] DoE Global Energy Storage Database. The shown figures exclude PSH

Exhibit 11

LDES project pipeline (excluding PSH)



Source: DOE Global Energy Storage Database

Box 3.

Large-scale aboveground PSH

PSH is a type of hydroelectric energy storage that consists of two different elevation water reservoirs that can generate power as water flows down from one to the other, passing through a turbine. Different configurations of these systems exist, being the most implemented aboveground open-loop PSH and closed-loop PSH. The former are connected to a naturally flowing water stream (i.e., on-stream), whereas the latter are not continuously connected to a river (i.e., off-stream).

Large-scale, aboveground PSH is the most used energy storage solution globally due to its mature technology, high efficiency, and low capital cost per unit of energy. Currently, around 160 GW of power capacity is installed globally, with another 130 GW planned or under construction. Future deployments concentrate in Asia, where China accounts for around 60 percent of global capacity announced, planned or under construction, the US, and India. Of the total capacity, more than 70 percent is associated with closed-loop projects (Exhibit 12). Existing and announced PSH projects generally have durations ranging from 10 to 24 hours (but in some cases reaching multiple days), and project sizes up to 3 GW.[19]

Total estimated investment in PSH projects

[19] International Hydropower Association.

over the last 10 years is estimated in USD 100-150 billion, with USD 230-320 billion more in thepipeline until 2030. System costs vary greatly depending on location, which mainly influences EPC costs, and system design (including duration of the system and technology). Global average capex costs are above USD 2,000 per kW. However, short-duration standalone designs in regions with very low EPC costs (like India), values below USD 1,000 per kW can be reached.

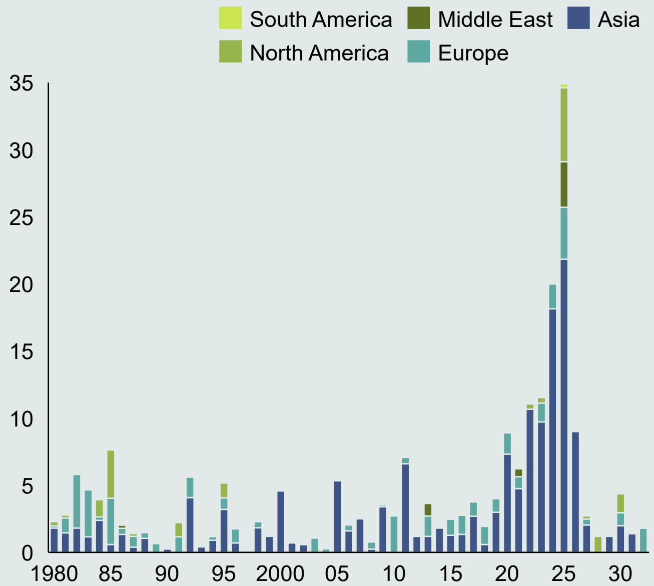
Large-scale aboveground PSH has historically been used for baseload applications, as it provides low-cost, dispatchable generation, and as a primary solution for grid stability due to its fast response times. Its major development constraints are a lack of available sites, long lead times, high construction costs, and environmental concerns. Nevertheless, it has potential to meet increased electrification needs and demand for zero-carbon molecules (such as hydrogen) to decarbonize hard-to-abate industries, particularly in emerging economies that hold the majority of the untapped natural potential and whose electricity demand may triple in the coming years.

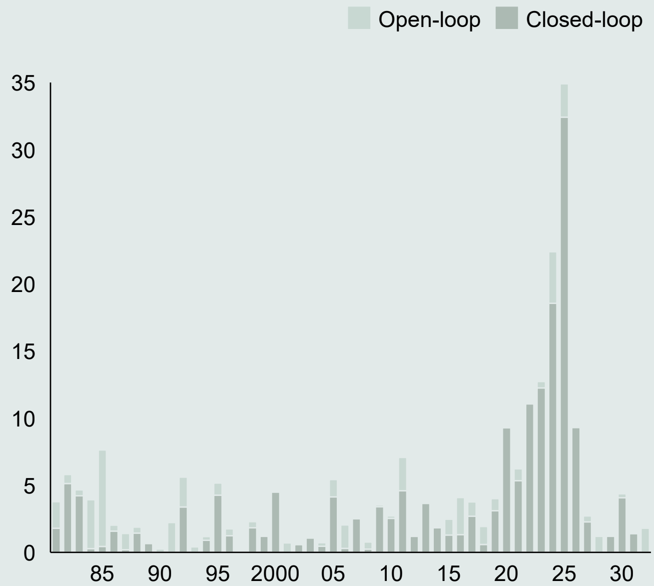
Exhibit 12

Annual PSH capacity additions by year

PSH capacity additions by year[1]

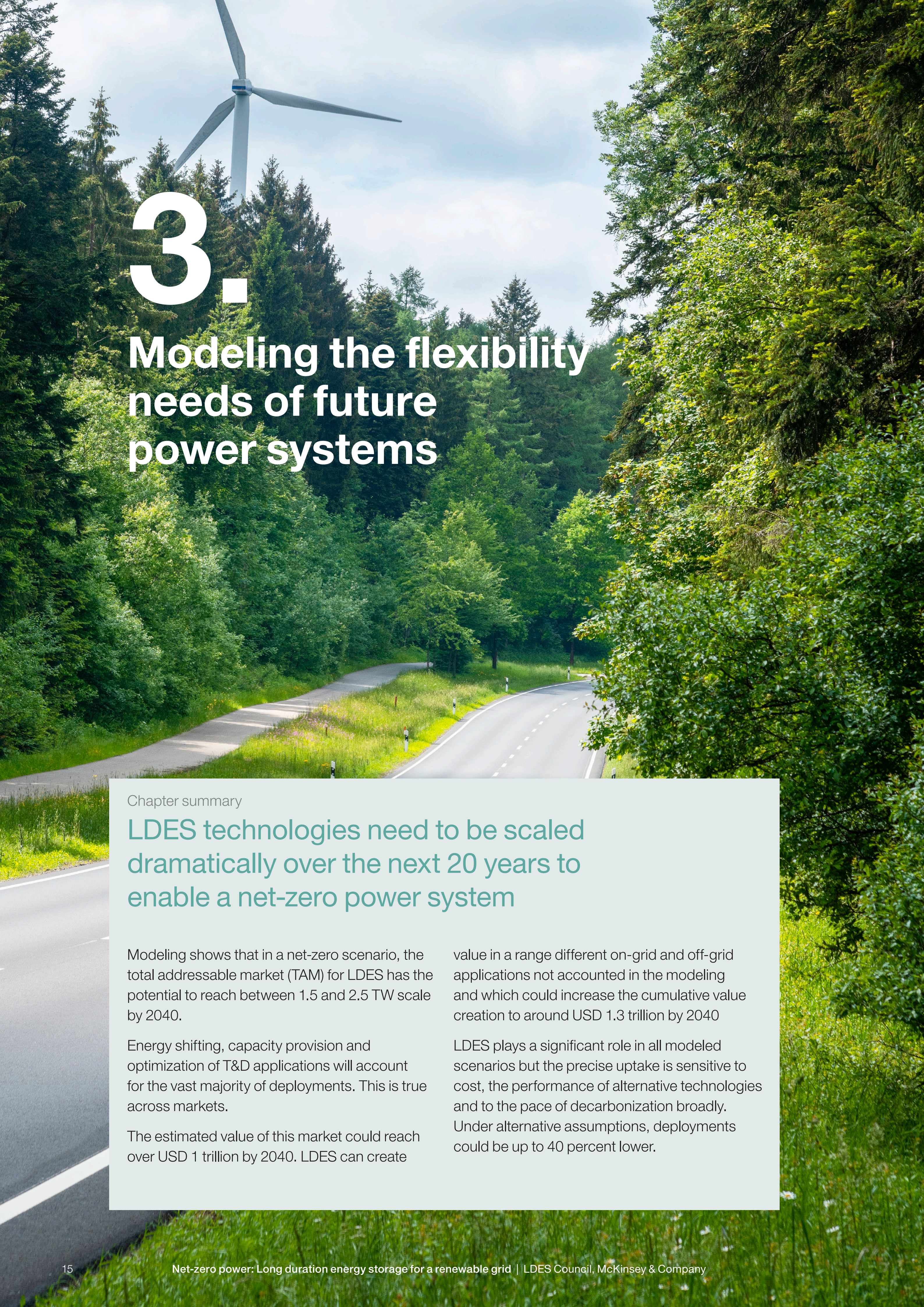
GW





1. Includes upgrades to existing plants and construction of new plants

Source: DOE; International Hydropower Association



3.

Modeling the flexibility needs of future power systems

Chapter summary

LDES technologies need to be scaled dramatically over the next 20 years to enable a net-zero power system

Modeling shows that in a net-zero scenario, the total addressable market (TAM) for LDES has the potential to reach between 1.5 and 2.5 TW scale by 2040.

Energy shifting, capacity provision and optimization of T&D applications will account for the vast majority of deployments. This is true across markets.

The estimated value of this market could reach over USD 1 trillion by 2040. LDES can create value in a range different on-grid and off-grid applications not accounted in the modeling and which could increase the cumulative value creation to around USD 1.3 trillion by 2040

LDES plays a significant role in all modeled scenarios but the precise uptake is sensitive to cost, the performance of alternative technologies and to the pace of decarbonization broadly. Under alternative assumptions, deployments could be up to 40 percent lower.

LDES is expected to play a significant role in achieving cost-effective decarbonization of bulk power systems and other specialized power applications. An overview of the projected total addressable market (TAM) for LDES based on modeling results is herein provided. The TAM values outlined below are an outcome on the cost-optimal net-zero trajectory for power systems and do not account for announced RE government targets or policy measures (more details on the modeling methodology are provided in Appendix A). Data ranges refer to the central and progressive scenarios.[20]

The total addressable market for LDES can reach a 1.5 to 2.5 TW scale by 2040 to achieve the required flexibility in net-zero power systems

Based on the projected cost trajectories, modeling results suggest that LDES will play a leading role in providing flexibility as power systems approach net zero.

LDES TAM can see initial deployment at scale from 2025 (30-40 GW, 1 TWh, or 6 to 8 times the current announced capacity), with accelerated growth toward 2030 (150 to 400 TW and 5 to 10 TWh) as RE penetration of the energy system continues. In 2025, more than 95 percent deployment will be driven by non-bulk grid applications such as island grids, remote and unreliable grid applications, and corporate RE power purchase agreements (PPAs). However, as bulk power systems achieve high RE penetration (around 60 to 70 percent globally) from 2030 onward, LDES capacity can accelerate toward the total value of 1.5 to 2.5 TW in 2040 (Exhibit 13). This represents 8 to 15 times the total energy storage capacity deployed today.

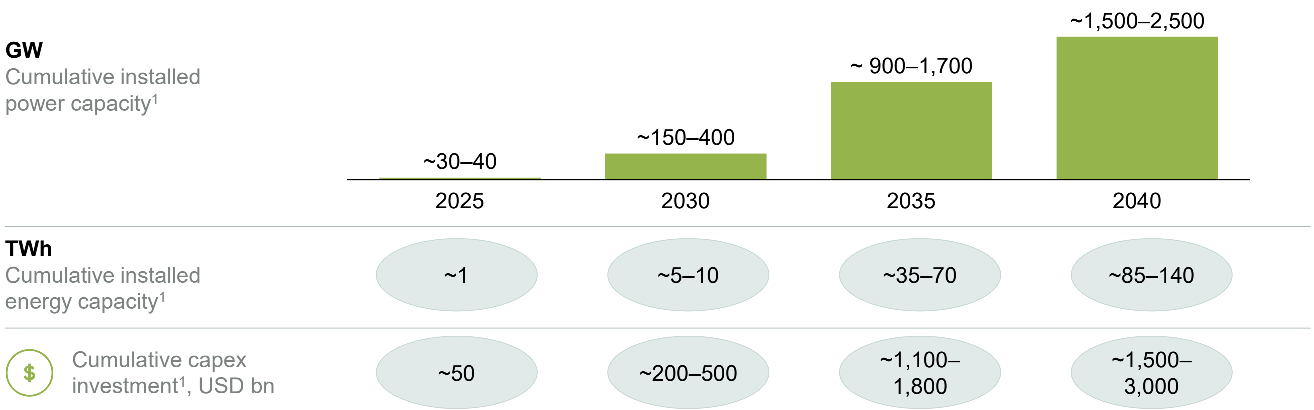
In the next five years, significant investment will be required to facilitate the widescale deployment of LDES and achieve a lower-cost decarbonization pathway. It is estimated that by 2025, around USD 50 billion will have to be deployed to install sufficient pilots and commercial plants for early decarbonization while enabling cost-reduction trajectories. This funding could come from private sources combined with a level of public support. Overall, the cumulative investment needed to realize deployments through 2040 is expected to reach USD 1.5 trillion to USD 3 trillion globally. While this is striking, this figure is comparable to what is invested in T&D networks every 2 to 4 years.

LDES can create value in a range of different on-grid and off-grid applications

LDES' projected technological and economic features allow them to serve a wide variety of end

Exhibit 13

LDES total addressable market and cumulative capex investment by year



1. Range is LDES central scenario and LDES progressive scenario.

[20] Central scenario: assumes first-quartile costs for LDES, conservative learning rates, and new-build nuclear capped at previous peak, and retired as planned. Progressive scenario: assumes first-quartile costs for LDES, aggressive learning rates, no new-build nuclear, and retired as planned.

uses. Five main value-creation segments have been identified (Exhibit 14), including:

- Energy shifting, capacity provision, and T&D optimization
- Optimization of energy for industries with remote or unreliable grids
- Isolated island grid optimization
- Firming for PPAs
- Stability services provision

Energy shifting, capacity provision, and T&D optimization in bulk power systems are projected to result in the largest proportion of deployment (80 to 90 percent in 2040); however, the other applications can also add significant value while ensuring full decarbonization of the power system (Exhibit 15). Additionally, it is projected that early market development in 2025 will be driven by supply optimization for industries with remote/off-grid or unreliable grid grids (50 GW), firming for PPAs (30 GW), and isolated island grid optimization (15 GW). The different applications are briefly described below, while the following section provides in-depth explanations of energy shifting, capacity provision and T&D optimization.

Optimization of energy for industries with remote or unreliable grids

LDES can become crucial to enabling onsite RE and ensuring continuous power supply where it is a requisite (for example, in continuous manufacturing lines). Relevant end users that may need a clean, reliable, and cost-effective power supply include large off-grid users (like mines, agribusinesses and military bases) and industrial users in locations with low grid reliability (like chemical and steel plants in less economically developed countries). In these cases, LDES would have advantages over grid expansion in terms of shorter lead times and fewer geographical constraints.

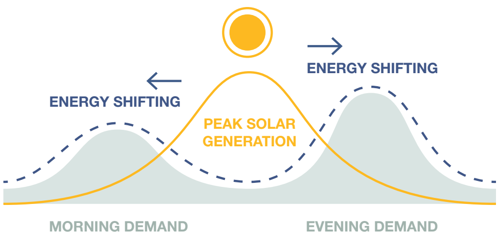
In total, cumulative LDES capacity deployed for the relevant applications could amount to 60 GW and 1.5 TWh by 2030 and 110 GW and around 4 TWh by 2040. The value created by LDES—

Exhibit 14

Overview of LDES applications

Energy shifting, capacity provision, and T&D optimization

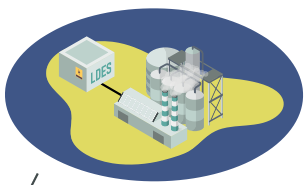
Peak generation from renewables does not align with peak demand for electricity. LDES can play a role in shifting electricity from times of high supply to times of high demand.



Alongside this, LDES provides value in other ways, for example ...

Supporting island grids

Power systems that are not connected to a large grid can use LDES to generate reliable power (e.g., a power grid on a small island).

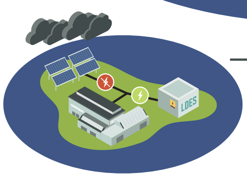


Providing stability services

Electricity grids require stability. LDES can be used to correct instabilities (e.g., transmission outages can be rectified by LDES).

Supporting industries with remote or unreliable grids

Large power users can use LDES to ensure reliable power in areas where they are isolated from the grid or the grid is unreliable (e.g., remote heavy industry).



Firming for RE PPAs

Renewable power-purchase agreements can use LDES to ensure that businesses can procure 100% renewable electricity.

Exhibit 15

Total addressable market and cumulative value creation by application by 2040

xx T&D optimization value xx Value/spend measures

	2040			
	Cumulative LDES			
Value created by LDES	Installed power capacity GW	Installed energy capacity TWh	Cumulative value creation USD bn	Annual LDES capex spend USD bn
Energy shifting, capacity provision, and T&D optimization	~1,300–2,300	~80–135	~470[1] / ~300–650[2]	~175–215
Optimization of energy for industry with remote or unreliable grids	~110	4	~120	~4–5
Isolated island grids	~90–100	3	~30–35	~10
Firming for PPAs	~40	2	~5–10	<1
Stability services provision (inertia)	0	0	~5–10[3]	na[4]
Total	~1,500–2,500	~85–140	~950–1,300	~190–230

Key assumptions
1. Based on reduction in cumulative system cost vs. "No LDES Case."
2. Value of transmission and distribution expansion deferral or substitution. Figures only account for infrastructure optimization and do not quantify the value of reduction in generation curtailment costs and reduction of energy not served.
3. Other services are potential material revenue streams for LDES, but not sized in this report.
4. Inertia provided through assets that are deployed for energy generation and capacity provisions, not through additional build-out.

reducing fossil fuel consumption, increasing operational uptime, and replacing fossil generation backup capacity—could total USD 20 billion to USD 30 billion by 2030 and around USD 120 billion by 2040.[21] The impact of climate change, including increased wildfire risk and its effect on grid reliability or corporate targets, could further accelerate adoption.

Isolated island grid optimization

LDES can support the stabilization and security of the supply of off-grid or microgrid facilities, including island power systems. For instance, these technologies could help decarbonize islands and remote communities by minimizing their dependency on diesel engines and fossil-based power. Furthermore, communities connected to weak power systems could also benefit from LDES inertia provision and other services.

By 2030, the cumulative installed capacity for isolated islands could amount to 15 GW and 150 GWh; by 2040, this could increase to 90 to 100 GW and around 3 TWh of installed capacity. The potential value creation of LDES arises from cost savings on fossil fuels and carbon emissions, totaling up to USD 30 billion by 2040.[22] Islands with accelerated decarbonization pathways or higher carbon prices could increase the deployment of LDES and create more value for these systems. The value of LDES in inland

[21] To estimate the LDES market size, different off-grid and backup LDES value propositions were identified with specific industrial and geographic scope, with each proposition sized following a tailored analysis. The duration for each application depends strongly on the specific use case and the geographic characteristics.

[22] For the market sizing, the most relevant islands (with a population of 0.1 million to 5 million) were identified and their energy storage needs estimated based on an in-depth analysis of particular case geographies to assess total LDES deployment. The sizing assumes a lowest cost pathway to decarbonizing island grids by 2040, implying a modular buildout of both Li-ion batteries and LDES to fulfill storage needs.

off-grid or isolated communities could have great potential as well, especially in developing nations where electricity needs are still either partially or fully unmet or depend on diesel generation.

Firming for RE power purchase agreements

LDES allows for securing premium PPAs with a particular baseload requirement. Both private and public organizations are increasingly interested in using RE to supply their electricity as a means to reduce operational costs, hedge against volatile fossil fuel prices and CO_2 costs, and achieve corporate environmental targets. Businesses with ambitious pledges to reduce carbon emissions typically rely on RE guarantees of origin (GOs)—commonly integrated into PPAs—to source zero-emission electricity. However, RE PPAs are often insufficient to decarbonize their total consumption; hence businesses frequently offset the remaining emissions with carbon credits purchased in voluntary carbon markets. LDES enables companies to increase their actual RE supply to near 100 percent while providing resiliency to operations. In the same way, utilities can use LDES to offer such 100 percent RE PPAs to their customers.

By 2025, the global cumulative deployment of LDES for firming RE PPAs could total 10 GW and 0.5 TWh, rising to around 40 GW and 2 TWh by 2040 and generating up to USD 10 billion in cumulative value in cost savings on RE GOs and carbon credits. This application should be primarily viewed as a near-term opportunity, as RE penetration in bulk grids will increase significantly beyond 2030 to provide 24/7 RE coverage. As a result, companies' willingness to pay premiums for storage for firming RE PPAs will likely decline.

To ensure near 100 percent RE supply, durations needed for this application are expected to be above 24 hours. Nevertheless, required durations will be dependent on the existing capacity mix of the grid.

Stability services provision (inertia or synthetic inertia)

LDES technologies can provide a wide range of ancillary services to maintain grid stability (exact services vary by technology). One of those services is inertia, which is growing in demand as RE penetration grows. A differentiating feature of LDES for conventional power plants is that LDES can provide inertia while ensuring 100 percent RE supply. Furthermore, mechanical and thermal LDES technologies can also offer inertia without grid-forming inverters, which would raise the system's total cost.

Suitable LDES technologies can capture value from inertia and stack it with other remunerated services such as capacity provision. The total value created from inertia accessible to LDES is estimated at USD 0.5 billion by 2030 and USD 5 billion to USD 10 billion globally by 2040, considering the costs of the next cheapest alternative (that is synchronous condensers combined with flywheels). However, it is unlikely that the inertia and stability services will ever justify the installation of LDES alone. On a freestanding basis, synchronous condensers are the more cost-effective inertia solution.

Grid systems with limited interconnections are expected to be of particular interest at the beginning of the market, as they have fewer alternative sources of grid stability. Pilots for this service have already commenced: for example, in the UK, a six-year tender for inertia provision was contracted in 2020.

Deep-dive: Energy shifting, capacity provision, and T&D optimization

LDES are expected to play a unique dual role in bulk power systems, avoiding the need to use hydrogen turbines for peaking capacity while also serving intra- and multiday cycling needs. During summer and winter demand peaks, LDES can discharge energy over several days to provide critical clean energy and capacity reserve; during shoulder seasons, LDES could primarily perform intraday and multiday energy shifting. In the very long duration ranges, at presently projected system costs, a mix of hydrogen turbines and LDES will likely be cost optimal. Nevertheless, more rapidly reducing costs or slower hydrogen cost reductions would influence the capacity mix.

Regarding the TAM, energy shifting and firm capacity provision in RE-intense power systems will be the largest market for LDES, accounting for 80 to 90 percent of deployed volumes in 2040. T&D expansion optimization could generate an additional cumulative value of between USD 300 billion and USD 650 billion by

2040, primarily through the complementation, deferral, or substitution of the distribution network, where investments are higher.

Reducing curtailment and energy not served could increase the value pool further. LDES also has the potential to provide distributed capacity to meet local needs while also providing a cost-effective alternative to lengthy T&D lead times. While not currently accounted in the TAM, distributed thermal LDES applications could be especially attractive where heating needs are also present given the high energy losses of heat transport.

If cost projections unfold as projected, LDES could account for a large share of countries' capacity mix. For instance, in the US, LDES could store around 10 to 15 percent of total energy consumed by 2040, displacing some Li-ion and hydrogen turbine capacity and reaching higher shares than these two technologies (Exhibit 16).

A balanced mix of flexibility durations for LDES will be necessary through 2040

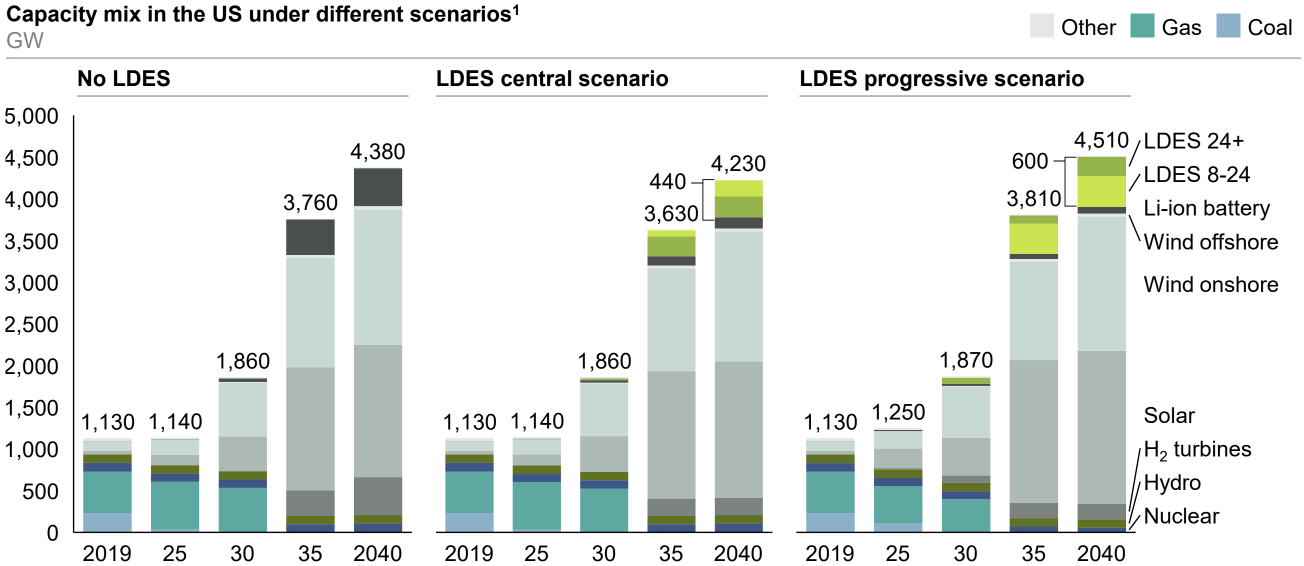
Given the lower RE share of the total generation mix, the largest share of flexibility needs before the end of this decade are likely to fall on shorter durations below 24 hours, providing intra- and interday cycling. Nevertheless, early deployment in the 24-hour or more range will also be driven by local conditions and specific applications (such as backup in low grid reliability regions or high availability corporate PPAs). Both duration archetypes are likely to see commercial demand in the near future.

By 2030, the projected deployed capacity of the 8-to-24-hour archetype[23] could account for more than 80 percent of total LDES power capacity and more than 60 percent of total LDES

Exhibit 16

Projected capacity mix in the US under a net zero 2040 trajectory and different cost development scenarios

Capacity mix in the US under different scenarios[1]
GW



Key assumptions

1. Two LDES archetypes were designed, one with 8–24 hours duration and one with 24–150 hours duration. The LDES central scenario is based on 1st-quartile cost data and conservative learning rate trajectories, while the LDES progressive scenario is based on 1st-quartile cost data and aggressive learning rate trajectories.
   - New nuclear capacity is only allowed to be built in the No LDES and LDES central scenarios, but capped at 50 GW by 2040. Existing capacity is assumed to be retired according to schedule.
   - Gas turbines are allowed to be built in the No LDES and LDES central scenarios, but no biomethane or H_2 co-firing is allowed.
   - H_2 turbines are allowed to be built in all scenarios, including gas turbine retrofits and new-build H_2 capacity.

[23] The 8-hour threshold does not imply that LDES is not expected to provide services below this duration.

energy capacity. LDES technologies that offer more than 24-hour flexibility could see significant growth after 2030, owing primarily to an increase in RE. Longer duration LDES technologies could account for roughly 80 percent of total cumulative energy capacity by 2040. Required investments for different duration installations are expected to follow a similar pattern to power capacity deployment due to the greater weight of this component in the total overall system costs (Exhibit 17).

RE growth and electrification could lead to increased demand for LDES systems across all markets

LDES has the potential to support the cost-optimal decarbonization of bulk power across all markets (Exhibit 18). The US shows the greatest need for LDES systems among the modeled locations, mainly due to limited transmission connections across the country. In this market, LDES would help in reducing curtailment and congestion, while increasing transmission utilization. Demand in Europe and Japan could primarily be driven by peaking capacity from 2035 to 2040, with longer average durations (above 50 hours) being installed.

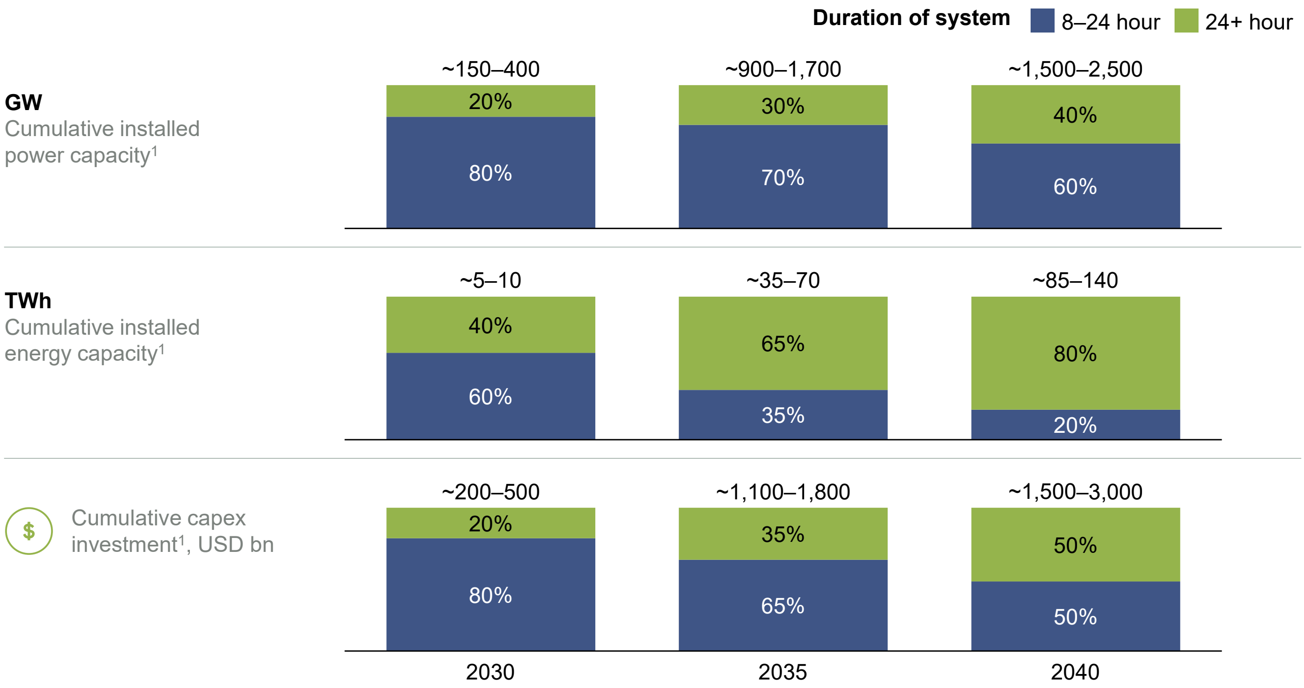
Regions with abundant RE resources and high solar penetration throughout the year, such as Australia and Chile, could mainly require shorter durations for bulk power services.

LDES demand in emerging markets will be driven not only by the replacement of fossil-based assets with RE, but also by increased electricity demand, which is expected to rise significantly in the coming years. LDES's projected TAM in India is 125 GW to 250 GW and 15 TWh to 25 TWh by 2040, with average installed durations in the 100-hour scale. However, systems will be providing the full range of flexibility durations, including intraday and multiday, with shorter durations greatly demanded in the short-term as the RE capacity ramps-up.

Policy measures and government targets could influence deployment pace and result in an earlier rollout than projected. For example, India's target of deploying 450 GW of RE by 2030 could result in a high demand for energy storage capacity before the end of this decade, accelerating LDES deployment. Similarly, the US' new commitment to zero-emissions electricity by 2035, as well as China's target of 1,200 GW of RE by 2030, could have a positive impact as well.

Exhibit 17

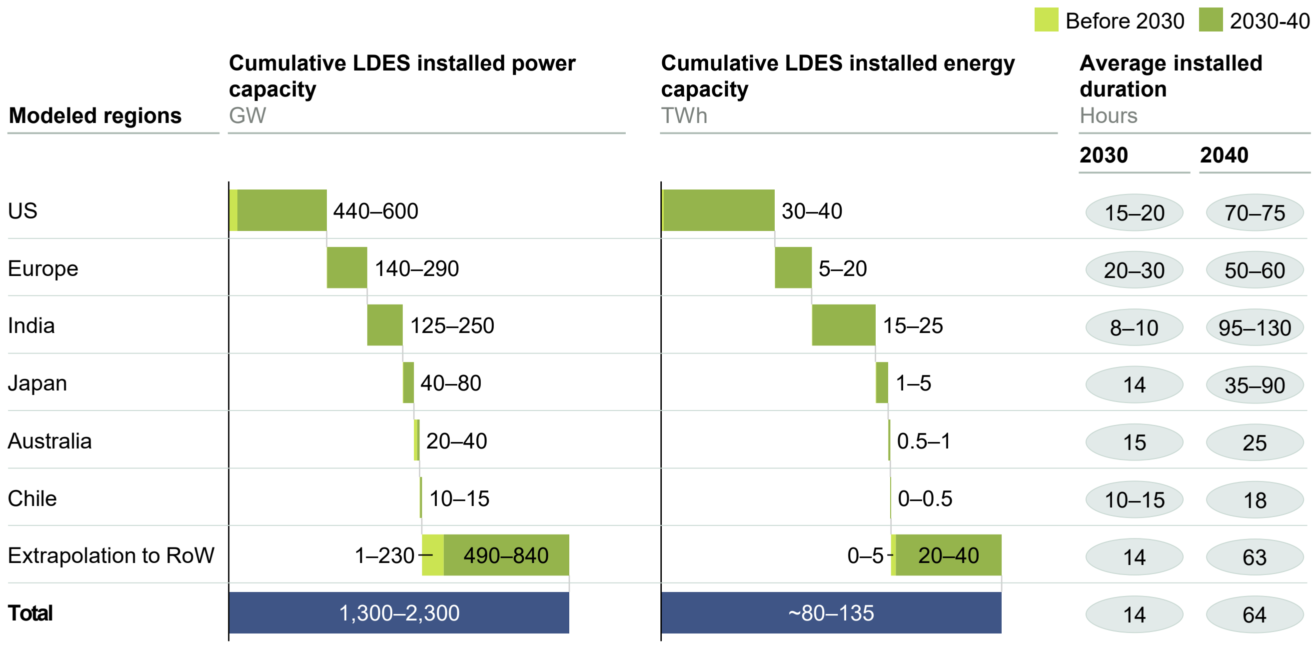
LDES total addressable market for the different archetypes



1. Range is LDES central scenario and LDES progressive scenario.

Exhibit 18

Total addressable market by modeled markets



The TAM is most sensitive to cost and performance, alternative technologies, and decarbonization developments

The future of power markets is by definition uncertain. Commitments and actions by public and private players, new market designs, and technological developments, are all highly interconnected and will ultimately determine whether climate targets are met. Similar unpredictability surrounds LDES, which in addition carries technology maturity risk.

Projections for LDES deployment are thus highly sensitive to different assumptions, as shown in Exhibit 19 (the figures are for the US market, but behaviors are representative of the rest of the world).

The projected TAM is most sensitive to weaker than projected LDES cost and performance developments. If companies only meet average capex cost-reduction trajectories, the take-up of LDES could be reduced by further Li-ion and hydrogen deployment (120 to 250 GW in the US by 2040). If the round-trip efficiency (RTE) of systems falling in the 8-to-24-hour archetype do not exceed 70 percent, Li-ion could take approximately 65 GW of LDES deployed. On the other hand, the impact on longer durations would be minimal, with only 15 GW being displaced by hydrogen.

Deviations in the cost projections of alternatives could significantly impact LDES adoption. If hydrogen costs decrease (for example, if hydrogen storage in salt caverns increases), an additional 90 TWh of hydrogen-based energy could be generated, displacing more than 170 GW of LDES capacity. Nevertheless, this is expected to have its limitations, given that lower-cost hydrogen requires infrastructure or geographical conditions that may be highly constrained. A more aggressive Li-ion cost scenario would replace roughly 40 GW of shorter duration LDES systems (namely the 8-to-24-hour archetype). On the contrary, slower Li-ion cost

Exhibit 19

Sensitivities to US bulk power market size to the variation of different parameters

2040, GW

x Bulk power total addressable market variance to central scenario; 8–24 hour; 24+ hour

Changes in model	Variance to central scenario in the US				Result observed
	Total	8–24 hour	24+ hour	Market variance	
Weaker cost and performance for 8–24 hour archetype (median assumed instead of 1st quartile)	-150	-250	100	+50% / -100%	+210 GW Li-ion storage; replacing 8–24 hour archetype as Li-ion becomes more competitive in short-durations
Weaker cost and performance for 24+ hour archetype (median assumed instead of 1st quartile)	-5	115	-120	-65% / +45%	+50 GW of H_2 turbines; LDES less competitive in firm capacity provision
Weaker cost and performance for both archetypes (median assumed instead of 1st quartile)	-245	-250	<5	+1% / -100%	+260 GW Li-ion storage and +70 GW H_2 turbines; LDES 24+ hour archetype energy capacity halved
Additional contingency costs for pre-commercial technology[1]	-420	-250	-170	-90% / -100%	+220 GW of H_2 capacity and 320 GW of Li-ion; LDES not competitive at this cost
Weaker RTE improvement for 8–24 hour archetype (frozen at 2025 level, ie, 70%)	-45	-65	20	+10% / -25%	+67 GW Li-ion storage; Li-ion more competitive in short-duration energy shifting
Weaker RTE improvement for 24+ hour archetype (frozen at 2025 level, ie, 50%)	5	20	-15	-10% / +10%	Minimal change, as no other competitive alternative in long-duration energy shifting

1. Project contingency spend for technologies that are in early stages of commercialization. Assumes 30% increase for all capex costs for technologies without a pilot plant, and 15% increase for technologies currently with pilot plants (based on Rubin et al. 2013).

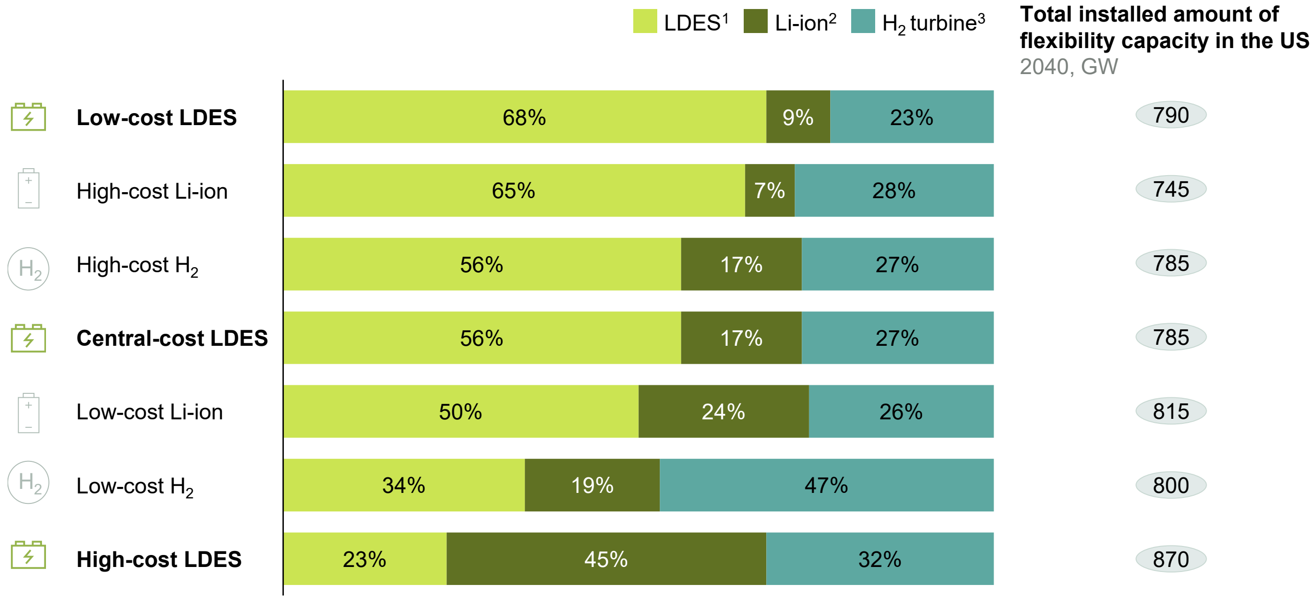
reductions would increase the market size of LDES below 24 hours by roughly 50 GW (Exhibit 20).[24]

Lastly, LDES deployment is closely tied to the rate of decarbonization and deployment of variable RE generation. A slower transition to net zero in power, say by 2050, or a 90 percent reduction in emissions by 2040, could see only 25 to 40 percent of the 1.5 to 2.5 TW power capacity and 85 to 140 TWh energy capacity deployed in 2040; although in this scenario installation would be likely deferred rather than eliminated altogether.

[24] All cases use central scenario assumptions, and test sensitivity to one cost axis at a time.

Exhibit 20

Capacity mix by flexibility technology under different cost sensitivities



Key assumptions

1. LDES: low cost represents 1st quartile cost data and fast learning rate cost-reduction scenario; central cost represents 1st quartile cost data and slow learning rate cost-reduction scenario; high cost presents median cost data and slow learning rate cost-reduction scenario.
2. Li-ion: high cost is based on McKinsey Battery Cost Model Reference Case; low cost assumes 10% decrease in capex in all years from McKinsey Battery Cost Model Aggressive Case.
3. Hydrogen: high cost assumes +$1/kg to H_2 price due to lower than expected investments; low cost assumes H_2 storage in salt caverns rather than in above ground steel tanks.

4.
Cost analysis

Chapter summary

Achieving the scales outlined in this report requires learning rates comparable to other emerging clean technologies to occur

Novel LDES are nascent technologies that will reduce in cost as they are scaled. The Council have identified that a large portion of the costs will have learning curves

Projected capex learning rates are between 12 to 18 percent, consistent with other similar breakthrough energy technologies such as offshore wind and batteries. Technology developments and gaining operational scale will be the largest drivers of cost improvements

The competitiveness of LDES is driven largely by energy storage capacity costs, which are expected to decline by 60 percent. The round-trip efficiency (RTE) of these technologies is also projected to improve by 10 to 15 percent

Some technologies are competitive today for a limited but growing number of applications. The levelized cost of storage (LCOS) analysis shows that if these learning curves are achieved, LDES is cost-competitive for durations above 6 hours and below 150 hours

- In 2030, LDES can be LCOS-competitive against Li-ion for durations above 6 hours, with a distinctive advantage above 9 hours
- In 2030, LDES can be LCOS-competitive against hydrogen turbines with the same operational profiles for durations below 150 hours

To overcome the current cost gap and technological uncertainties of this nascent market, the right ecosystem that accelerates investments should be in place

Technology costs roadmap

As with any new technology, competitive costs and performance are critical to ensuring widespread adoption and providing societal benefits versus alternatives. For LDES, the key parameters to consider are energy capacity cost[25] (USD per kWh) or energy capex, power capacity cost[26] (USD per kW) or power capex, operation and maintenance (O&M) cost (USD per kW-year), and round-trip efficiency (RTE).[27]

Because the cost breakdown changes significantly with duration, two LDES archetypes (8 to 24 hours[28] and 24 hours or more) have been created based on more than 10,000 data points from the LDES Council. The analysis shows top performers' projections for both archetypes.[29] Only the most competitive LDES technologies are expected to receive the capital to scale up over the next decade and therefore constitute the dominant portion of the mix by 2030. The energy capex has been chosen as the defining metric of top performers since the total cost of decarbonization (like the system cost) is especially sensitive to this metric in deeply decarbonized scenarios.

Current system costs and performance are comparable to other nascent technologies on the verge of commercialization

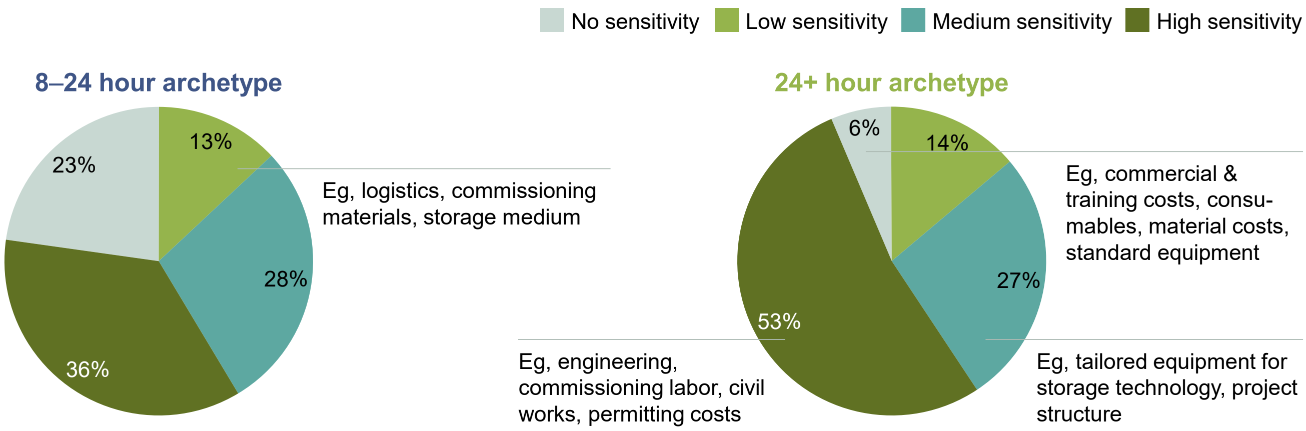
LDES show potential for cost savings as a result of technological learning rates. Both archetypes are sensitive to learning rates, with 75 to 90 percent of their capex being influenced to some extent (Exhibit 21). In the 8-to-24-hour archetype, 35 percent of capex is susceptible to learning rates, rising to more than 50 percent in the 24-hour or more archetype as the impact of procurement costs decreases.

Cost reductions are likely to be dictated by two factors: 1) cost improvements from increased industrywide deployment, supplier development, and supply chain learnings; and 2) improved cost reductions linked to manufacturing advances and increased production volumes (namely learning at a manufacturer level).

The LDES cost-reduction rate compared to other low-carbon flexibility systems, such as Li-ion and hydrogen turbines, will determine the level of uptake of these technologies. However, in specific applications, the distinguishing factors

Exhibit 21

Capex breakdown by sensitivity to learning rates (2025)



Source: LDES Council member technology benchmarking

[25] Capex associated with the energy storage equipment, representing the investment required to store energy.
[26] Capex associated with charge and discharge equipment and BoP. The BoP includes auxiliary components such as inverters, circuit breakers, or transformers.
[27] The ratio of the total energy discharged over the total energy charged. It is calculated as an average value in standard temperature and pressure conditions. It accounts for the electricity lost in the inverter for those storage technologies which need one and does not include ancillary consumptions.
[28] The 8-hour threshold does not imply that LDES is not expected to provide services below this duration.
[29] Based on top-quartile data.

of LDES such as modularity, short time to market, and the ability to provide a diverse set of services, will be critical in unlocking business cases in the short term.

Energy and power capex could decline by 60 percent in the next 15 years, while RTE could grow by 10 to 15 percent as the commercialization of systems accelerates

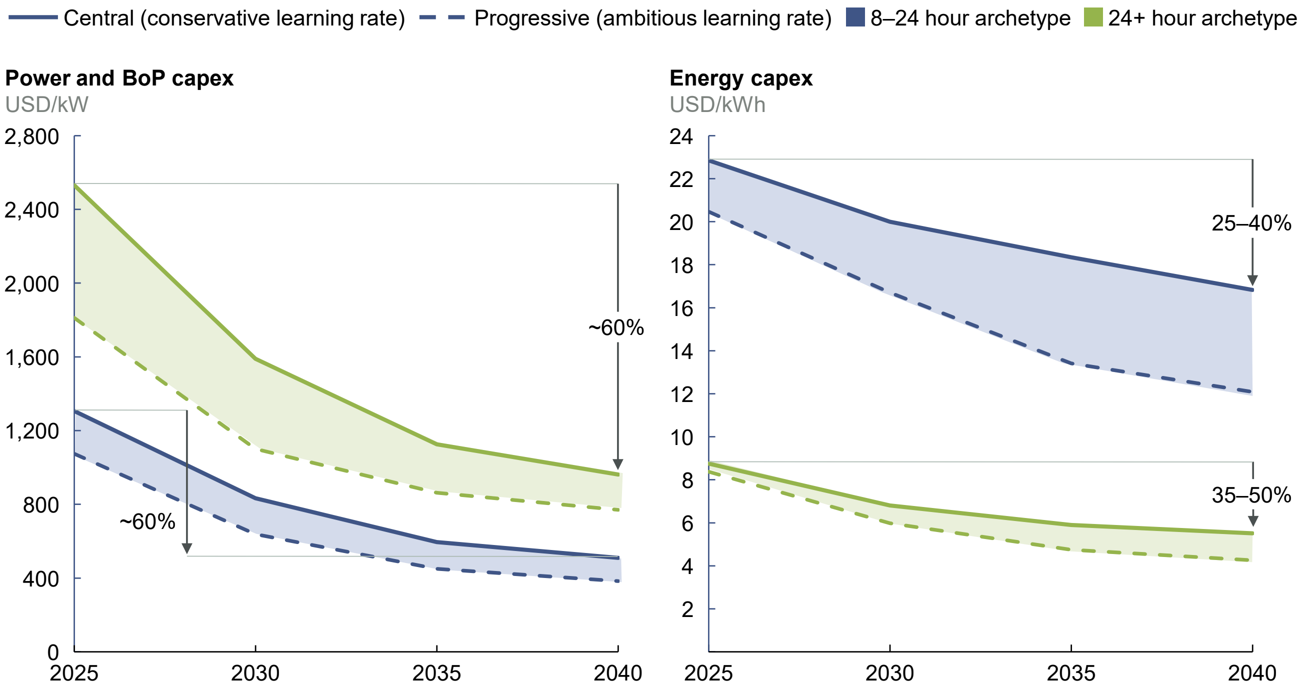
In 2040, the power capex is likely to be between USD 380 and USD 960 per kW and the energy capex between USD 4 and USD 17 per kWh. This compares to USD 60 to 110 per kW and USD 70 to 80 per kWh for Li-ion batteries, and to USD 800 to 900 per kW for single cycle gas turbines in 2040. The power capex, which includes charging and discharging equipment and BoP costs, is expected to show a comparable overall decline of around 60 percent across both archetypes, experiencing the steepest drop in the next ten years. Power-only-related costs are likely to decrease faster than BoP costs as they mainly comprise standard equipment. In terms of the absolute power capex, lower duration systems present lower values, as they are usually optimized to be competitive at shorter durations and higher cycling profiles. This advantage tends to be reduced for longer storage durations as the energy capex becomes the main cost driver.

The energy capex differs more significantly across archetypes and scenarios. The energy capex of the 24-hour or more archetype can reach considerably lower values than the 8-to-24-hour archetype (around three times lower), enabling the design of these systems for longer durations due to the lower cycling requirements to generate profits (Exhibit 22). For more information on the energy capex of median performers please refer to Box 4.

The O&M costs can experience a significant decrease between 2025 and 2040, down to USD 1.5 to USD 10 per kW annually, thanks to the deployment of larger facilities. The 24-hour or more archetype is likely to achieve O&M per kW around ten times lower than the 8-to-24-hour archetype, a benefit mainly due to scale effects. Longer duration systems present a lower RTE of about 55 percent compared to above 75 percent

Exhibit 22

LDES power and energy capex trajectories



Source: LDES Council member technology benchmarking

for shorter duration systems by 2040 (Exhibit 23). Most of the RTE increase could be achieved before 2035 and is largely attributable to material science breakthroughs and adjustments in the system design. For more information on the RTE of median performers please refer to Box 4.

Projected capex learning rates for LDES systems are consistent with similar breakthrough energy technologies such as wind, PV, and electrolyzers

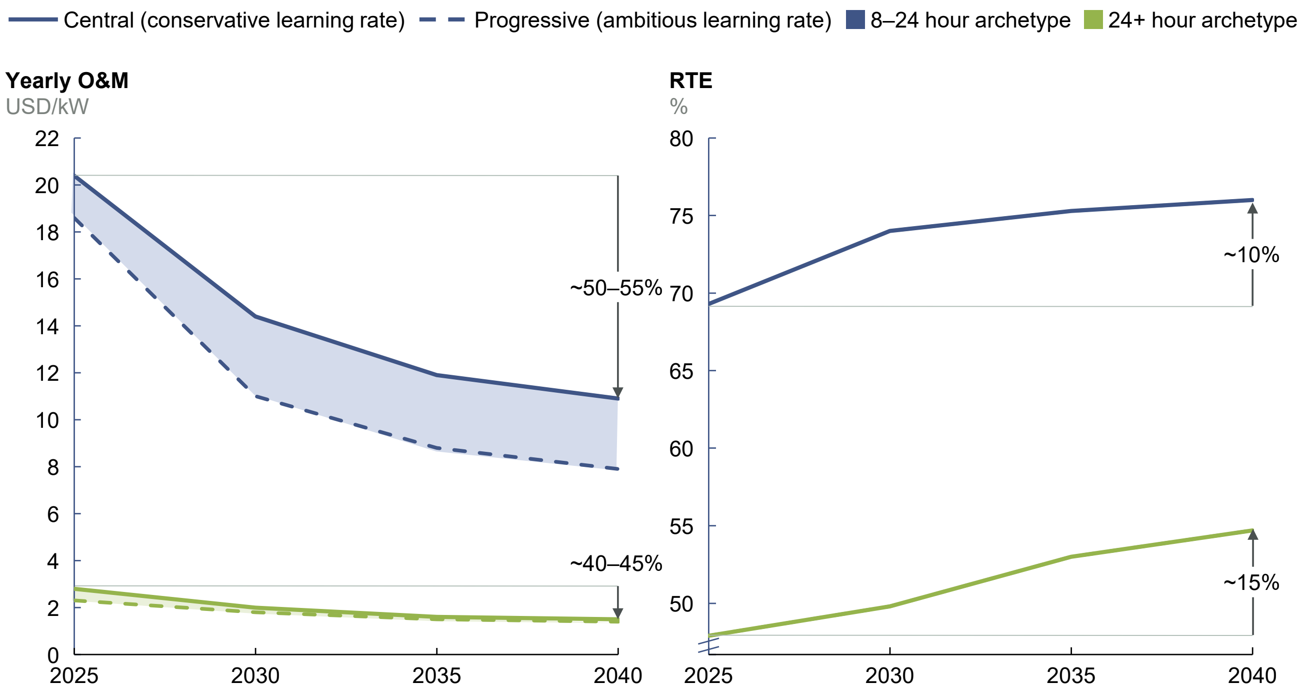
The total equipment capex is of primary importance in driving the total cost of ownership to competitiveness. Learning rates are a measure of how costs decrease as output increases. For example, doubling the installed capacity of PV and wind technology is associated with an 18 to 24 percent cost reduction.

Emerging LDES technologies have a significant potential to achieve economies of scale and further decrease costs through R&D. The industry anticipates learning rates of 12 to 18 percent for the benchmarked period, based on technology providers' forecast deployments calculated on a per-technology basis. LDES technologies' learning rates align with similar energy technologies' historical data, as seen in Exhibit 25. However, these learning rates are ambiguous—as are any forecasts of nascent technologies—as they have little historical information to draw on.

The potential learning rates for different LDES technologies also vary as they are influenced by the equipment used, bill of material, and sensitivity to capex improvements. Generally, more mature technologies, such as electrochemical batteries, have lower-than-average learning rates (four to five percentage points below average), while novel LDES technologies, such as mechanical or thermal energy storage, may enjoy higher-than-average learning rates (up to three and five percentage points respectively).

Exhibit 23

LDES's yearly O&M and RTE benchmark capex reduction



Source: LDES Council member technology benchmarking

Box 4.

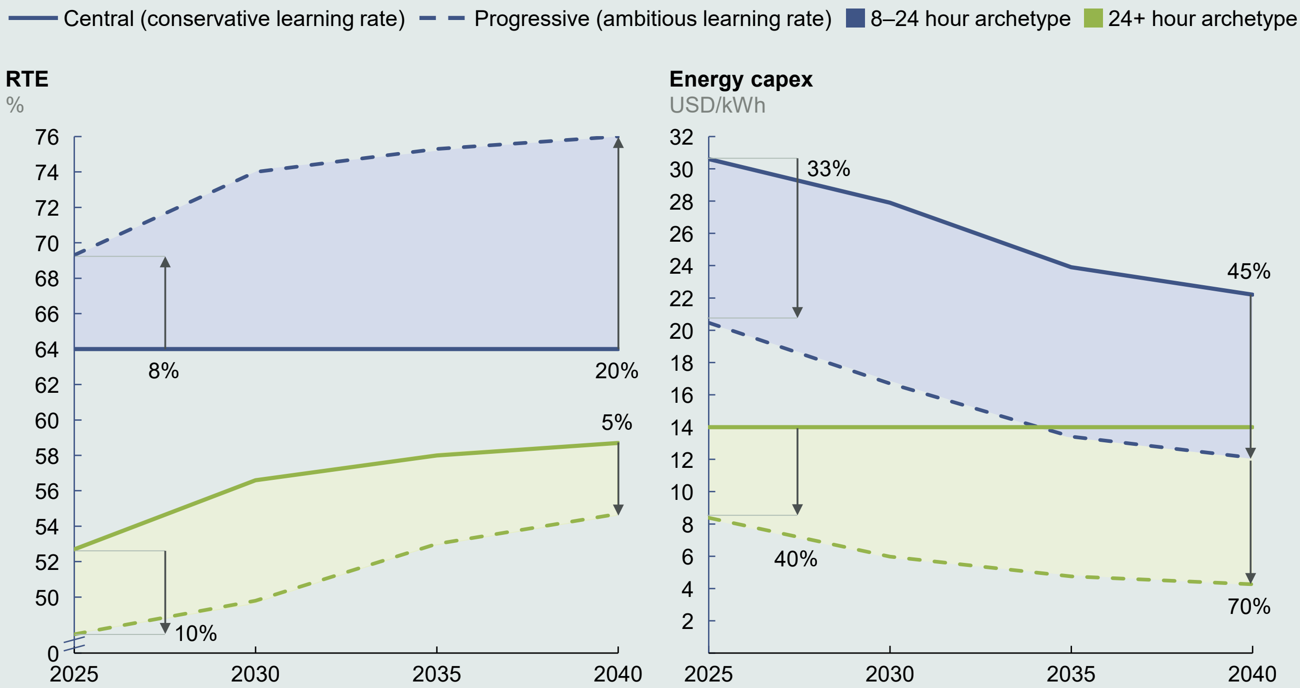
Top performance data compared to median performance data

To achieve greater societal benefits and be competitive with other low-carbon storage technologies, the broader LDES industry must achieve the objectives set by the most competitive market players.

The gap between median and top-quartile performance data must also be covered for the LDES industry to achieve the results of this study. This will require the industry as a whole to overachieve on today's projections, which has already proven possible for other energy technologies when supported by policies and industrial objectives. Exhibit 24 presents the gap between the median and top quartile. The current aggregation methodology does not create artificial best-in-class players as demonstrated by the fact that top-quartile players in terms of energy capex also present a slightly lower RTE than the median.

Exhibit 24

LDES's benchmark capex reduction for top-quartile and median performance data



Source: LDES Council member technology benchmarking

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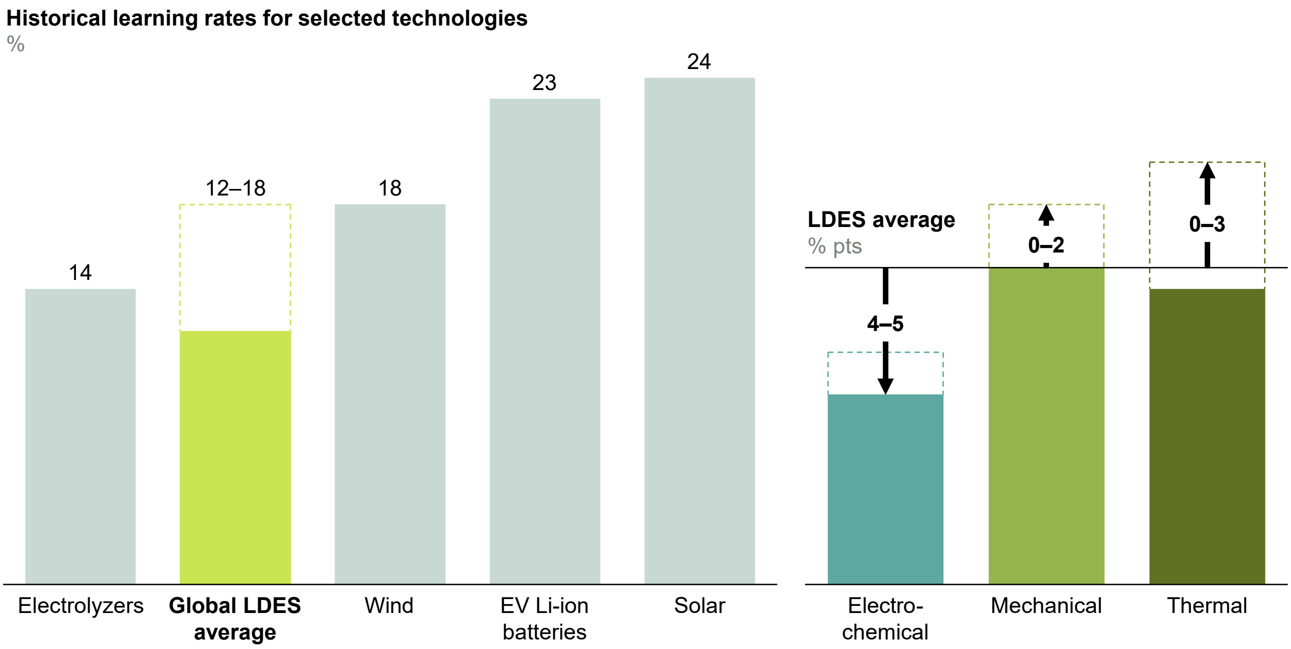
Technology developments and gaining operational scale will be the largest drivers of cost improvements

R&D and volume will be key levers to realize aspirational cost trajectories and will require attention from the industry to be competitive. The 45 percent reduction for the 8-to-24-hour archetype and the 50 percent reduction for the 24-hour or more archetype until 2035 will mainly be driven by increased efficiencies—as a result of R&D—and scale, depending on the maturity level of each technology. Manufacturing and supply chain improvements will have a slightly

Exhibit 25

Historical learning rates for selected clean technologies and LDES technology families



Source: LDES Council member technology benchmarking

lower impact on the overall cost projections (Exhibit 26). However, they will still play a fundamental role in reaching cost-competitiveness.

The expected LDES cost-reduction trajectory is comparable with Li-ion battery and hydrogen energy storage cost projections in the next 20 years

The LDES system capex reduction forecast (55 to 60 percent by 2040) is comparable to cost-reduction expectations reported for utility-scale Li-ion systems (around 70 percent) and LCOE for hydrogen turbines (around 50 percent).[30] Moreover, the pace of reduction is similar across the technology groups, with the fastest learning phase occurring in the next decade. This implies that the relative competitive positioning and economic trade-offs between the technologies will likely remain similar over this period.

Li-ion and hydrogen face a level of future uncertainty comparable with LDES but can rely on a higher pledged level of capital investment and attention at the moment. There are many detailed perspectives on the cost-reduction trajectory of Li-ion and hydrogen,[31] underlining that each technology shows distinct cost-reduction drivers. These diverge from the levers shown for LDES.

Li-ion's future trajectory will be set by the demand in EVs (more than 85 percent of future total demand from 2021 to 2040), with storage potentially accounting for up to 10 percent of this demand. As such, learning rates of Li-ion batteries will be linked more closely to the EVs demand than the output of Li-ion stationary storage. Similar chemistries still allow similar learning-by-doing cost reductions, procurement scale benefits, and cell assembly benefits from manufacturing scale that apply across EVs and stationary batteries. The largest cost component of Li-ion stationary systems is the battery pack (50 percent in 2021), which is often common to both EVs and stationary applications and will account for 32 percentage points of the cost reduction due to greater value chain integration, manufacturing scale, and improvements in raw material refinement. The remaining capex will be reduced by refining and specialization in other hardware systems, engineering, procurement and construction fees, and soft costs.

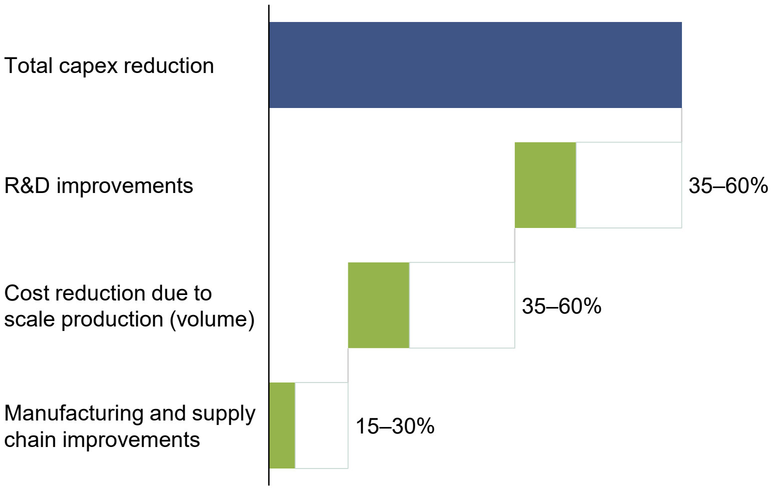
The hydrogen-to-power cost trajectory is most sensitive to fuel costs, which currently contribute

Exhibit 26

Projected impact of different cost reduction levers on total system cost

Breakdown of cost-reduction levers, 2025–40

% of total reduction



R&D improvements	Increased cost efficiency, eg, due to design optimizations of major components and efficiency of materials used
Cost reduction due to scale production (volume)	Learnings from volumes, eg, more efficient project management and scaling up of logistics
Manufacturing and supply chain improvements	Increased manufacturing efficiency, eg, leaner production processes, cost-efficient sourcing, automated assembly

Source: LDES Council member technology benchmarking

30 "Hydrogen economy outlook," BNEF, 2020.
31 NREL; AEMO ISP; BNEF; Hydrogen Council.

to around 70 to 80 percent of the LCOE, with hydrogen turbine (or fuel cells) and transport costs being the other key components. The cost of renewable hydrogen is expected to decline by an average of between 67 and 74 percent globally by 2040, becoming widely competitive in the early 2030s.22 This hydrogen fuel cost will be set by the development of hydrogen for industrial, commercial, and transport decarbonization applications. In turn, the extensive use of hydrogen in these sectors will drive developments in electrolyzer technologies, hydrogen transport (including infrastructure, pipelines, and shipping), and fuel cell technology improvements that underpin the cost reduction of hydrogen for power.

One other aspect to consider with hydrogen-to-power systems is the synergy with hydrogen used in other energy systems. In a future with high levels of hydrogen used in nonpower decarbonization and transported by pipeline, the interplay could significantly influence power system economics. For example, in times of reduced global economic growth or recession, there could be an oversupply of hydrogen power as cyclical industries such as steel and cement reduce demand.

Levelized cost of storage (LCOS) competitive benchmarking

Analysis of LCOS in static conditions and comparable operations helps define durations where LDES can compete

The LCOS provides a discounted unit value of all technical and economic factors that influence the lifetime cost of storing electricity by taking a technology cost perspective rather than a system one. However, when considering the potential for LDES to replace other technologies, such as gas turbines or transmission, or its contribution to the overall system value, LCOS alone is insufficient. In these cases, it is also critical to consider the operational profiles, duration requirements, commodity prices, and other system conditions. Aside from the cost, several other application and instance-specific properties will influence the choice of a technology (such as, presence and safety constraints in densely populated areas and the availability of waste heat supply).

The LCOS can be the first effective proxy to evaluate the cost competitiveness of LDES solutions at different storage durations. With consistent global assumptions and utilization rates, LDES can be compared to Li-ion in shorter durations and hydrogen turbines in longer durations through the LCOS metric. Acknowledging that storage duration is a continuum and that partial charge or discharge often plays a significant role in achieving the flexibility requirements of a project, this static analysis is helpful to understand the range of durations where the cost and performance parameters of LDES could allow for the most competitive applications. For more details on the methodology and assumptions please refer to Appendix A.

LDES can be LCOS-competitive compared to Li-ion batteries for durations above 6 hours, with a distinct advantage above 9 hours

Assuming a constant yearly utilization of 45 percent (average real storage utilization reflected by the modeling), by 2030 LDES will have a lower LCOS than Li-ion batteries in applications requiring more than 9 hours of storage, with USD 80 to USD 95 per megawatt-hour (MWh) (Exhibit 27). Competitiveness against Li-ion batteries is more challenging in applications with storage durations of less than 6 hours, as Li-ion's low power capex costs drive low prices at shorter durations. Due to comparable learning rates between Li-ion and LDES technologies, the relative cost competitiveness of LDES technologies to Li-ion is unlikely to change significantly before 2035.

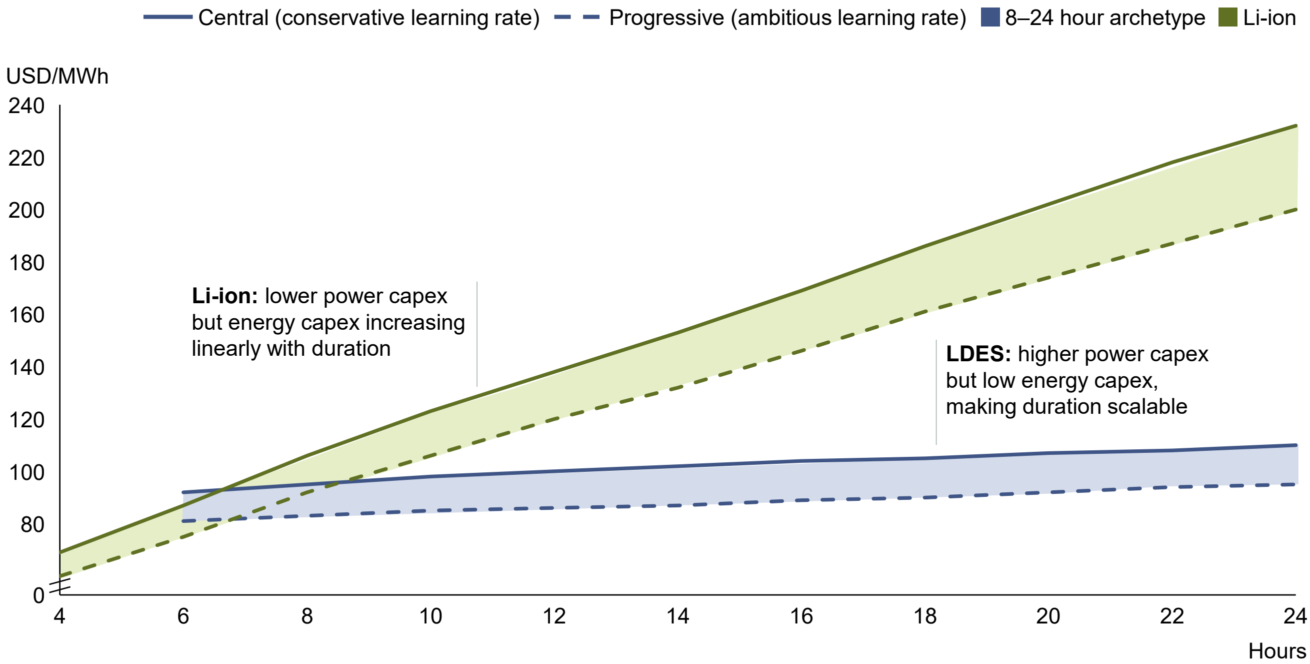
In peaking capacity applications, LDES are likely to be LCOS-competitive against hydrogen turbines for consecutive discharge durations of less than 150 hours

Some LDES already match the operational profile of gas peakers[32] when providing grid reliability. For similar use cases, LDES is expected to show a cost-competitive advantage against hydrogen turbines in durations below

[32] "Solving the clean energy and climate justice puzzle," Form Energy, 2020.

Exhibit 27

Energy storage LCOS competitiveness by duration for Li-ion and LDES, 2030



100 hours when able to match the turbines' operational profile (Exhibit 28). In this analysis, a capacity factor of 15 percent, corresponding to the maximum utilization associated with a peaking capacity asset, is assumed for the hydrogen turbine. As the assumed capacity utilisation grows, the extent to which an LDES system can be a potential substitute for turbines decreases.

A multi-technology portfolio approach, including hydrogen turbines, LDES, and other long-duration solutions, is likely to be the most economic path to full decarbonization. Even though durations longer than 6 days cover most renewable generation "dips", new dispatchable generation will still need to be part of the capacity mix to ensure reliability in case of longer extreme weather events (for example, weeks with little sunshine and wind).

Asset utilization and lifetime average charging costs will be major operational breakeven components

The LCOS is highly dependent on boundary conditions—including specific market conditions, geographical location, and end applications—that will shape the technology's competitiveness (Exhibit 29).

Combined, electricity prices and storage utilization have the most substantial impact on the LCOS. For example, a charging electricity price of USD 30 per MWh and a 70 percent utilization rate results in an LCOS of USD 70 per MWh. The same LCOS is obtained if the LDES has an utilization rate of 45 percent and a charging electricity price of USD 15 per MWh in the 8 to 24 hour archetype (in line with RE LCOE in the world's most competitive regions) and USD 120 per MWh in the 24 hour or more archetype..

The RTE is an influential variable in the LCOS calculation (with a one-on-one correlation) because it influences charging and discharging requirements; however, its impact on LDES competitiveness and value is limited when compared to the energy capex. From the standpoint of LCOS sensitivity, the energy capex will have a direct impact on the design energy storage capacity of the system and on its utilization. RTE's improvement is frequently compromised by technological limitations.

Exhibit 28

Energy storage LCOS comparison by duration for hydrogen and LDES, 2030

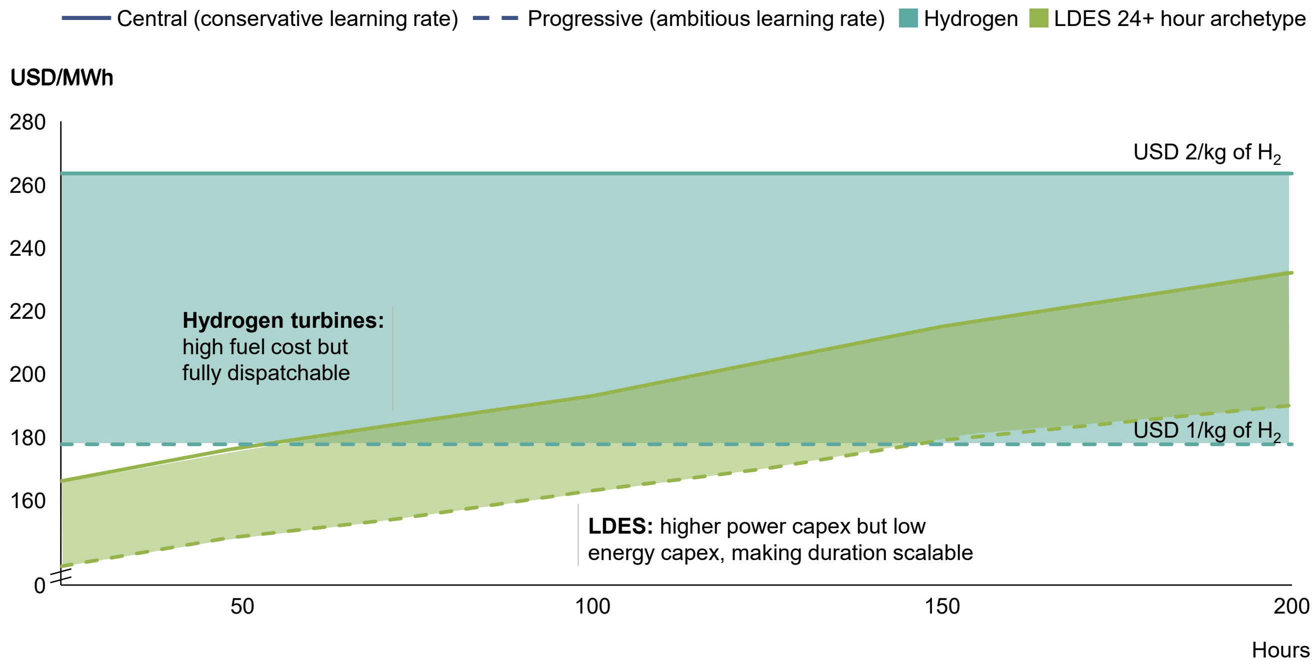


Exhibit 29

Impacts on LCOS by ranging different input metrics, 2030

Parameter	8–24 hour archetype, 16 hours duration: Range	LCOS impact 2030, USD/MWh	Sensitivity to 5% change %	24+ hour archetype, 100 hours duration: Range	LCOS impact 2030, USD/MWh	Sensitivity to 5% change %
Prior to change		87			151	
Per energy capex USD/kWh	8–25	81 – 92	3	3–9	135 – 167	1
RTE %	90–40	71 – 140	6	75–25	110 – 268	4
Per power capex & BoP USD/kW	400–960	76 – 97	2	690–1,510	130 – 173	2
Opex USD/kWh	5–20	80 – 90	3	0.9–2.6	150 – 152	0
Electricity price USD/MWh	16–46	70 – 112	3	16–46	123 – 183	2
Utilization %	70–20	71 – 138	6	70–20	119 – 257	4

5.

LDES business cases

Chapter summary

LDES can create significantly economic and environmental benefit in the energy system if opportunities are created to pursue it

LDES assets are being commercially installed today, having returns on investment of more than 10 percent

To enable wider commercial deployment, LDES must achieve optimal cost-decrease and performance trajectories, as well as technical maturity

LDES value creation could benefit a broad range of customer archetypes. Four customer business cases illustrate the potential for value creation in the near future for some of the applications. Integrated utilities with future transmission bottlenecks benefit from LDES but face uncertainty on monetization

Market support mechanisms and regulatory incentives are required to in the short term to unlock the competitiveness of certain business cases and attract the necessary private capital

LDES projects will have comparable investment returns to other energy technologies by 2025, although market support will be critical in the short term

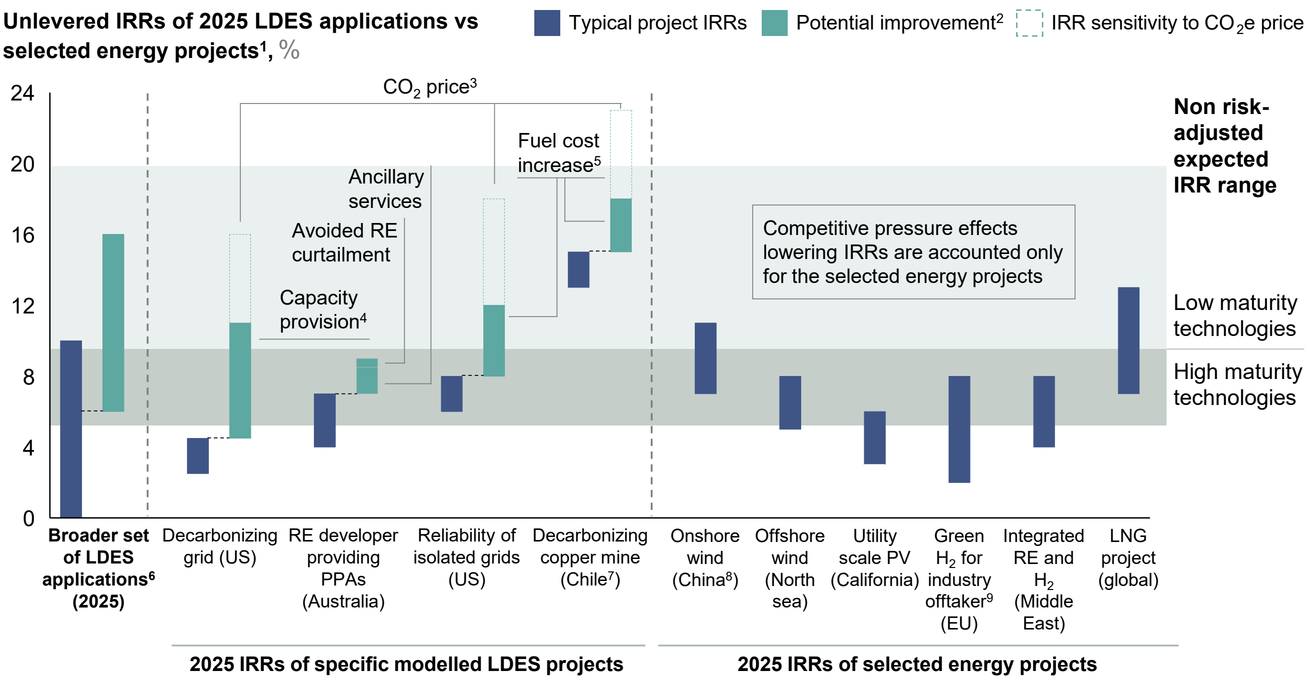
In 2025, all the modeled LDES applications have internal rates of return (IRRs) well above the minimum investor attractiveness threshold and comparable with benchmarked IRRs of current mature energy projects. The high profitability is mainly attributable to the cost trajectory assumptions, which will require early deployments and investments supported by an appropriate market ecosystem (explored in Chapter 6).

For the majority of modeled business cases, the implementation of market mechanisms is required to bring the IRRs well above 10 percent before 2025 (Exhibit 30). Here the example of earlier renewable development is instructive. IRRs of LDES projects deploying in 2025 that purely rely on existing regulations and revenue streams are comparable with those of PV and wind at the very beginning of their commercialization. Their growth was assisted by dedicated public policy support schemes. In a similar fashion, LDES competitiveness could be unlocked by policy actions in line with the net-zero goals that capture their value. In general, beyond the business cases studies in this report,

Exhibit 30

Unlevered LDES IRRs for 2025 compared to other technologies

Unlevered IRRs of 2025 LDES applications vs selected energy projects[1], %



Key assumptions

1. Projects IRR are based on country level or competitive landscape benchmarks and thus are not exhaustive of the overall market expected returns
2. Potential improvement in IRR enabled by market mechanisms and regulatory improvements
3. CO_2 prices modelled for three scenarios: base scenario (60 USD/tCO_2e in 2030), medium scenario (75 USD/tCO_2e in 2030) and high scenario (100 USD/tCO_2e in 2030)
4. Maximum modeled weighted average capacity cost of 16.7 USD/kW per month (from LA Basin, California)
5. Islanded grid from 150 USD/MWh to 200 USD/MWh, off-grid mine from 250 USD/MWh to 300 USD/MWh
6. Includes the broader list of LDES projects, not explicitly modelled in this report (
7. Particularly favorable project and not necessarily representative of all mining applications
8. Benchmarked wind onshore projects IRRs in Shandong and Jiangsu regions
9. Assuming subsidies commensurate with track record in currently deployed projects, project IRR is scale-dependent.

Source: Grant Thornton; Renewable energy discount rate survey 2018

LDES presents a wider spectrum of applications, related IRRs and sensitivities, described under the "broader set of LDES applications" category.

LDES assets are being commercially installed today, but there are key challenges to be overcome for wider commercial deployment

Different use cases of deploying LDES in the near term (2025 to 2030) are explored through four case examples. The selected cases have a positive net present value (NPV), driven by an IRR above 10 percent; this improves as commercial operation dates are shifted to 2030 and beyond, benefitting from system cost reductions and lower capital investment requirements. Where LDES deployment is not yet economical, several potential mechanisms could unlock financial viability (explored in Chapter 6).

The different LDES use cases could benefit a broad range of customers, including integrated utilities, independent power producers, T&D system operators, corporates with environmental, social, and corporate governance commitments, industrials with high uptime requirements, isolated island communities, military bases, and public and healthcare services with backup requirements. While the common theme is the need for power resilience, each use case is driven by local regulation. For example, public utilities with grid-system operating functions are likely catered for by LDES applications for energy shifting, capacity provision, T&D optimization, and stability service provision. Whereas corporate players, such as RE developers or owners or industrial customers, are more likely to be interested in LDES' ability to firm PPAs or optimize energy sourcing for offtake in a remote or unreliable grid.

The business case of an integrated US-based utility is described below. The other case examples are summarized in Exhibit 31 and described in Appendix B.

Exhibit 31

Assessment of LDES-driven business cases

Application	Case example	Customer example	IRR (potential improvement)	Value drivers for LDES	Key unlocks
Energy shifting, capacity provision, and T&D optimization	**US-based utility**	Integrated utilities with significant RE build-out and transmission bottlenecks between generation and demand	~3% (+11%)	T&D optimization Capacity provision CO_2e cost savings RE curtailment reduction	Market mechanisms enable remuneration of CO_2e bene-fits for LDES asset owners Regulatory options or incentives ensure WACC commensurate with RE development Sustained carbon price in line with NDCs[1]
Stability services provision (eg, inertia)					
Firming for PPAs	**RE developer in Australia**	RE developers or owners looking to serve corporate RE PPAs with firmed capacity	~7%	Firmed capacity RE PPA premiums	Increase certainty for LDES developers through long-term contracting
Isolated island grid optimization	**Isolated island integrated utility in the US**	Integrated utilities serving isolated island power systems with decarbonization ambitions but limited interconnectivity	~7% (+5%)	Production cost savings CO_2e cost savings	Regulatory options or incentives ensure WACC commensurate with RES development
Optimization of energy for industries with remote/ unreliable grids	**Diesel-powered copper mine in Chile**	Industrial customers looking to reduce the costs of energy supply and reduce carbon footprint of products	~15% (+4%)	Production cost savings CO_2e cost savings	Market mechanisms enable remuneration of CO_2e benefits for LDES asset owners
On-demand RE peak power	**RE developer in India**	RE developer in India providing morning and evening peak supply as well as off-peak generation	~10% (+2%)	Peak and off-peak power supply	Increased electricity pricing spread and higher need for clean dispatchable peaking power

1. Nationally determined contributions.

A US case study shows how integrated utilities can benefit from multiple LDES applications but face uncertainty on monetization

In the US, several integrated utilities are responsible for their local grid's energy generation and operation. They typically rely on carbon-intensive gas peaking plants to support local load and reliability. In cases where there is a geographic divide between generation and demand, transmission bottlenecks arise. Limited transfer capabilities and challenges when building new transmissions drive the need to improve the utilization of T&D networks and maintain reliability in the low-carbon future. Given the vast amounts of RE capacity that will be connected, critical choices about T&D investments for the next decades need to be made.

For these customers, an LDES system could provide multiple solutions. The installation of an LDES system displaces a share of the demand for electricity from gas-peaking power plants and reduces the production and emission costs. In addition, LDES storage capacity can absorb a large volume of electricity currently being curtailed during peak production times. LDES also provides reserve capacity to replace the gas power plants that currently deliver this service. As LDES increases, the utilization of the T&D network and costly capacity expansion can be optimized. (Exhibit 32)

Exhibit 32

Integrated US utility case example

Main LDES application(s) | Value | Net value | Cost | Accessible value with market mechanisms in place

Customer profile

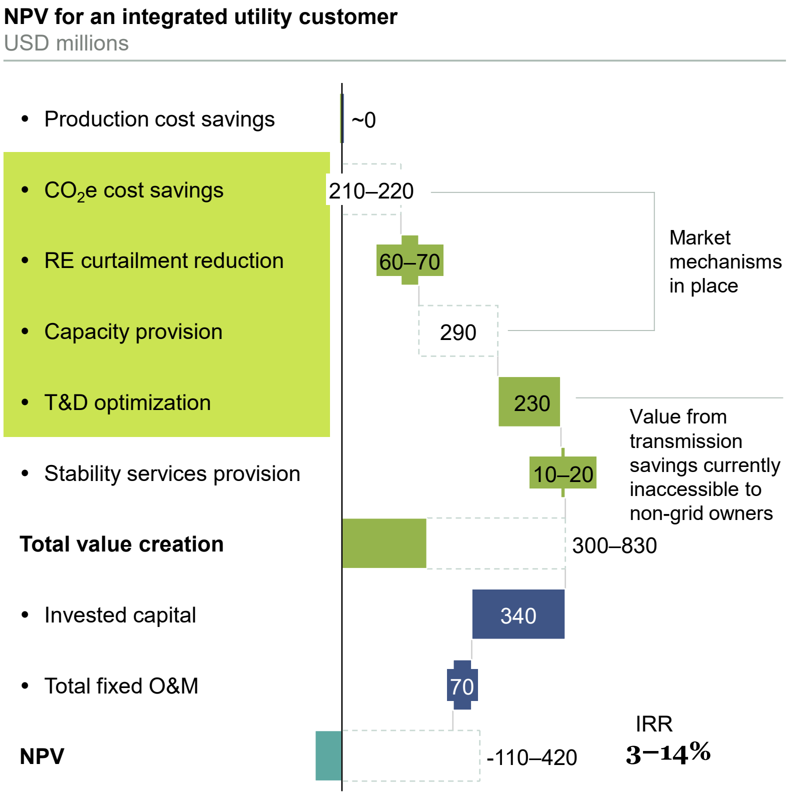
Integrated utility in the US that depends on gas-peaking plants for reliability

Geographic divide between generation and demand with transmission bottlenecks

Challenges building new transmission

LDES assets to displace gas-peaker plants and improve RE utilization

Potential LDES system: 200 MW/2,000 MWh (10 hours); systems of longer durations are also seeing demand driven by utilities' long-term needs



Assumptions	*Final investment decision date*	*Commercial operation date*	*CO_2e price scenario*	*WACC*
	2023	*2025*	*Base case*	*6%*

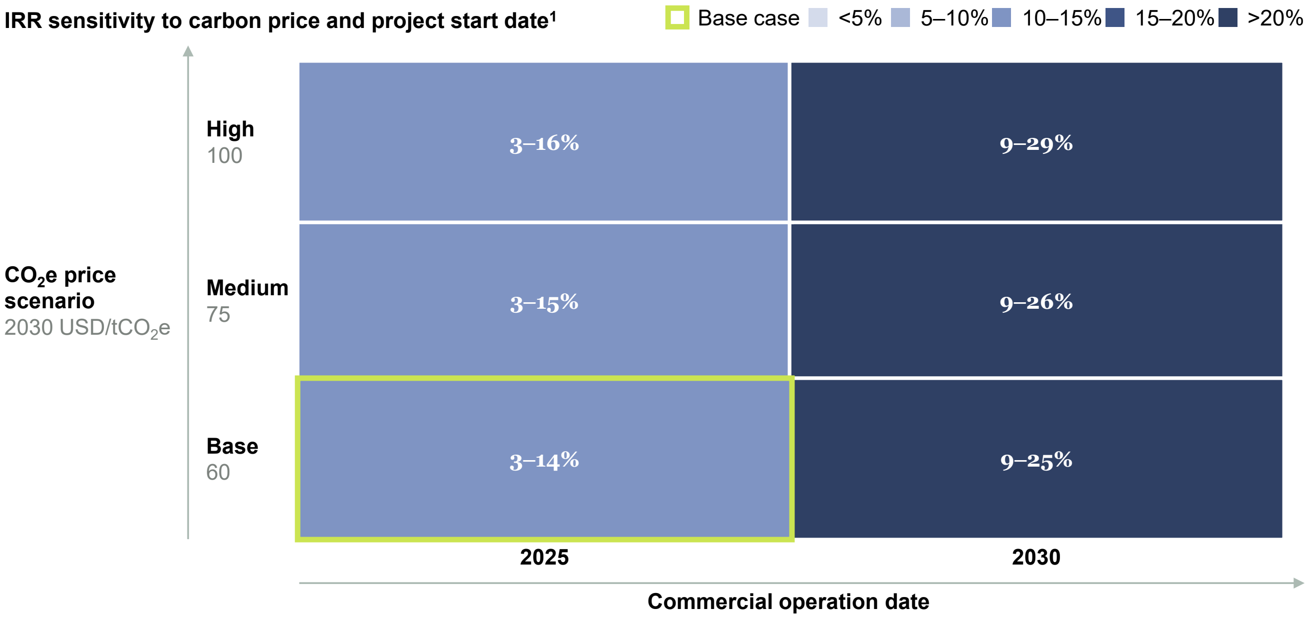
The case shows that the NPV ranges between -USD 110 million and +USD 420 million. To access the higher end of this range, market mechanisms would have to be fully in place to ensure the benefits can be captured, especially if the customer is not an integrated utility that also operates the grid.

Transmission optimization, capacity provision, and CO_2e cost savings (USD 230 million, USD 290 million, and USD 210 million to USD 220 million, respectively) are the most significant contributors to the overall value creation of USD 300 million to USD 830 million. Transmission savings compare transmission costs to storage buildout for different scenarios to determine the relative storage investment required to offset transmission spend. CO_2e cost savings originate from the opportunity of replacing a gas peaking plant with LDES.

The economics of this case are sensitive to CO_2e prices and project start dates. The IRR increases significantly to between 9 and 25 percent when the commercial operation date moves to 2030, with the construction of the system taking place in the two years prior. Furthermore, accelerated CO_2e price increases could result in IRRs of up to 16 and 29 percent with operation dates by 2025 and 2030, respectively. (Exhibit 33)

Exhibit 33

Integrated utility case example – US, IRR sensitivity



1. Lower end of range for value capture in markets with appropriate mechanisms; higher end of range for full value potential.

To ensure the financial viability of LDES for integrated utilities, several key conditions have been identified. First, the LDES asset owner would be able to monetize the benefit created by CO_2e emission reductions through adequate market mechanisms. Second, regulatory options or incentives would be in place to bring the owner's cost of capital in line with that of other decarbonization efforts. Third, CO_2e prices would be rising in line with the increasing ambitions of national emission reduction plans, such as nationally determined contributions (NDCs). Fourth, RE owners would use LDES charging as much as possible, especially since net-zero grids are not fully deployed yet; this could be ensured by schemes that facilitate the traceability of energy generation and certify its origin.

6.

Road to competitiveness and key market enablers

Chapter summary

Three potential actions could help unlock LDES value by changing the way storage is regulated and remunerated

Driving the economic and technical maturity of LDES technologies should be aligned with the large-scale deployment of RE to achieve maximum societal cost reductions

A supportive ecosystem with concrete actions would be beneficial for the prompt development of the market. In particular, 3 key areas for action have been identified:

1. Long-term system planning could help attract adequate levels of private investment:
   - National upfront planning to optimize the capacity mix, grid infrastructure, and storage
   - Clear RE targets to create demand for energy storage and provide visibility to investors
   - International coordination to enhance efforts across markets and regions
2. Support for first deployments and scaling-up capabilities to lower investors' barrier of entry and risk
   - Dedicated support programs to reach cost cutting potential and test new market mechanisms
   - Targeted support schemes such as RE and LDES tenders to incentivize take-up by sector players
   - Support for manufacturing and supply chain improvement to increase scale and reduce capex
3. Market creation to ensure financial returns during the lifetime of the assets
   - Market mechanisms and designs to ensure compensation for flexibility provision
   - Enabling regulation to facilitate LDES uptake (e.g. safety standards, market rules that capture LDES value)

A lack of supportive market could significantly delay the deployment of LDES technologies

The timely maturity of LDES technologies is essential to enable the optimal integration of RE in power systems

LDES can play a vital role in decarbonizing the world's power sector. By 2040, LDES deployment could result in the avoidance of 1.5 to 2.3 Gt CO_2eq per year[33] (around 10 to 15 percent of today's power sector emissions) by enabling dispatchable RE and the replacement of emitting plants.

Most importantly, they can do so at no additional societal cost. The overall cost of power systems could be reduced by around USD 35 billion annually by 2040 in the US alone (Exhibit 34) under a 100 percent decarbonization scenario and top quartile performance, of which USD 5 billion would come from the application of LDES in T&D expansion projects.

In order to realize their full potential, LDES technologies need to reach technical and economic maturity alongside the widespread deployment of RE. Whether LDES developers achieve the cost-reduction trajectories outlined in this study or not depends on improved technological designs, the streamlining and optimization of manufacturing capacities, and scale factors. Furthermore, rapid technological progress will be essential to ensure their adoption at a fast pace. Only the technologies that mature quickly enough to meet market demands are likely to make it into the portfolio of solutions that support the power system transition.

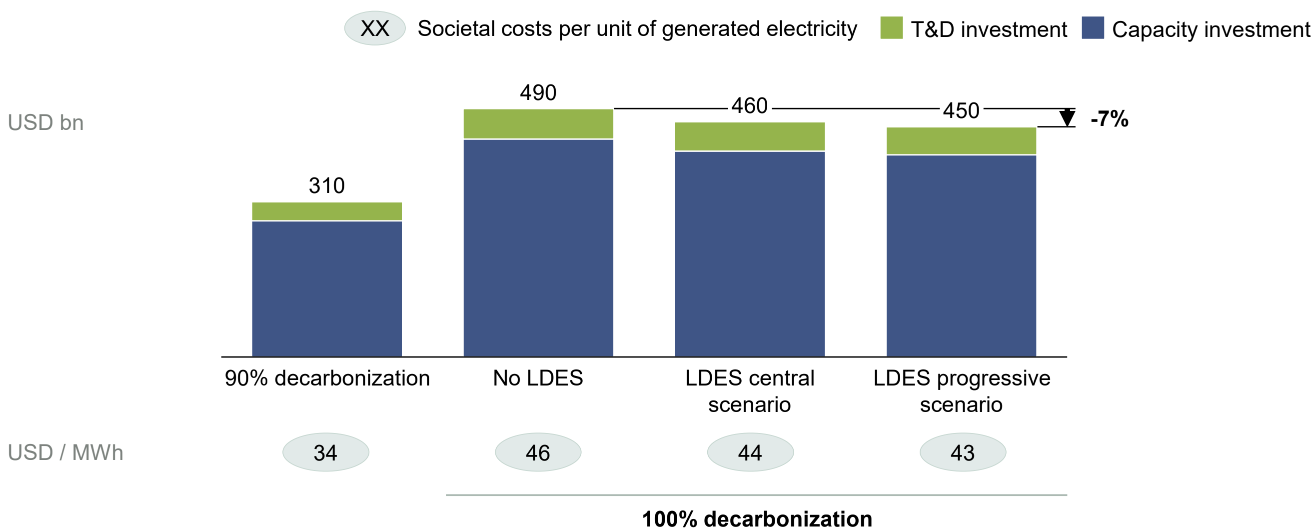
Potential accelerators for the adoption of LDES may emerge. They could include a faster trajectory to net-zero power systems than the one assumed in this study, either at a local level or in regions or countries with high decarbonization targets. These would naturally demand solutions to de-risk and balance the integration of large amounts of RE. In addition, sustained and incremental CO_2 pricing will enhance the value of specific business cases by creating new revenue streams and reinforcing existing ones. Last but not least, the evolution of alternative solutions and their deployment constraints (such as supply chain shortages for Li-ion and high demand in the EVs segment) could heavily influence the demand for LDES technologies.

Achieving the optimal LDES capacity deployment through 2040 will require significant investments

Overall, using LDES to upgrade electric power systems in the most cost-effective manner will necessitate significant private investment. Cumulative capex investments of USD 50 billion are likely to be required to deploy the projected

Exhibit 34

Total in-year societal cost of bulk energy shifting



[33] Assuming that the total electricity discharged by LDES globally in 2040 would be emissions-free and substitute traditional gas peaking capacity.

capacity until 2025, with USD 1.5 trillion to USD 3 trillion needed globally until 2040 to realize progressive cost projections.

LDES technologies would also benefit from government support to kick-start the market as quickly as the net-zero transition demands. Short-term funding for these technologies can be viewed as a long-term investment that will pay off in the form of a lower-cost power system and a de-risked transition.

A supportive ecosystem with concrete actions would be beneficial for the prompt development of the market

To overcome the current cost gap and technological uncertainties of this nascent market, the LDES Council believes that governments and business leaders can catalyze the development of the market by creating the right ecosystem that accelerates investments.

Three key dimensions where support actions with the highest impact have been identified:

4. Long-term system planning to create the right investment signals
5. Supporting the first deployments and scaling-up capabilities to kick-start the market
6. Creating the market to capture LDES value and allow monetization

1. Long-term system planning to create the right investment signals

Clear commitments to net-zero emissions and comprehensive decarbonization road maps from governments and industry are essential to meet climate targets. Long-term system planning could attract adequate levels of private investment in both technological advancements and early system deployment, ensuring the timely development of enabling solutions such as LDES.

LDES can significantly improve the reliability and resilience of power systems. Net-zero power systems could benefit from upfront planning (similar to Publicly Owned Utility Integrated Resource Plans in the US) to optimize the capacity mix, grid infrastructure, and storage deployment. Upfront planning would minimize the number of emergency procurements, which frequently result in the acquisition of equipment unsuitable for long-term system needs.

Academic and industry progress in building new capacity expansion models has led to an emerging set of best practices about how to plan low carbon grids that rely substantially on renewables and storage. Where possible, capacity expansion models and the investment decisions they require should be based on: at least one full year of grid operations at hourly resolution, including weather and load variability that reflects day-to-day, week-to-week, and season-to-season fluctuations; multiple weather years and key future system conditions, such as technological availability, commodity prices, or other variables. This would lower consumer costs as well as the risk of unanticipated power outages and supply chain constraints.

Power system planning that includes LDES is already taking place in some advanced regions. For example, California has already procured MW-scale LDES, and New South Wales, Australia, announced last year the procurement of 2 GW of LDES in its Electricity Infrastructure Roadmap.

Clear RE targets and strategies to accelerate permitting would also create early demand for energy storage to balance the variability in renewable generation. RE generation, T&D grids, and energy storage are highly interconnected. As such, clear strategies on RE integration, storage, and grid upgrades would provide visibility to investors and incentivize uptake by RE developers.

Lastly, international coordination is also essential to establishing the world's path to net-zero power. Coordination of efforts yields principles and lessons that can be replicated across markets. Applications or regions with similar needs could join forces to monitor the technologies that best support the energy transition, establishing industrial or regional networks capable of formulating needs and providing knowledge. All players need to continue to expand the knowledge base on LDES technology capabilities, value, and development trajectories.

2. Supporting the first deployments and scaling-up capabilities to kick-start the market

The majority of novel LDES technologies have not reached full commercial maturity yet, which presents a barrier for raising large amounts of private capital. Without an established market for LDES and a track-record of the performance of these systems, investor perceptions of high risks will limit funding and constrain the ability of developers to continue testing and improving their technologies.

As a result, dedicated support programs for large-scale demonstration plants would be essential to ensure that these technologies can reach their full technological and cost-reduction potential and that new market mechanisms can be tested. Such support could take many forms, some of which are listed below, and should be implemented in the short term to accelerate deployment.

For example, for the deployment of utility-scale, grid-connected demonstration plants, government-funded grants and financial instruments would be critical. Grants would accelerate design improvements (for example, in the RTE), reduce costs through R&D, and decrease uncertainties around operational performance, which would de-risk such projects for investors.

Initiatives are already underway in countries such as the UK, where the Department for Business, Energy & Industrial Strategy launched a USD 100 million LDES demonstration competition in early 2021 to accelerate project commercialization. Similarly, the US Department of Energy has launched a program to reduce costs of LDES of more than 10 hours of duration by 90 percent in one decade. The program has requested a budget of more than USD 1 billion. In the EU, the Innovation Fund also provides grants to energy storage projects based on innovative technologies. Not only grants, but financial instruments (such as blending financing instruments, thematic growth instruments, or credit enhancement mechanisms) would help to catalyze private funding and de-risk early projects.

Society could also learn from successful support schemes offered to other clean technologies such as solar or wind (e.g. tenders that reward best-performing technologies against determined criteria), and implement similar measures on a technology-neutral basis. Incentivizing sector players' uptake (such as RE players, system operators or off-takers) and collaboration with LDES technology providers can also accelerate early LDES deployment. Early movers (like mining companies or data centers) willing to cover the green premium will be essential to kick-start the market and develop learning curves. Tenders for RE co-located with storage with a minimum discharge duration, public-private partnerships or early market mechanisms could accelerate uptake. In this way, the maturity of the technologies would benefit from early positive cash flows that could be reinvested in further improvements while refining market creation.

Similarly, manufacturing and supply chain improvements could reduce the total capex by 15-30 percent. This support could include increasing manufacturing efficiency, automated assembly, and cost-effective sourcing.

To achieve full decarbonization, cleantech solutions would be needed in harder-to-decarbonize applications. These include the provision of backup power for critical loads, such as hospitals or telecommunication towers, where decarbonization by any technology will entail higher costs than the use of fossil-fuel-based installations. LDES are suitable for these backup applications; however, the low utilization implied with backup usage may lead to unfavorable economics.

3. Creating the market to capture LDES value and allow monetization

Even at the commercial-readiness stage, risks surrounding the future-cost trajectories and the revenues assets can capture during their lifetimes will remain. Current markets generally do not capture the full value of LDES since:

- Power markets are mostly short-term (such as day-ahead, intraday markets) and generally do not provide long-term agreements that could de-risk capital;
- Multiday and multiweek market signals are weak compared to intraday, and therefore storage technologies are incentivized to cycle multiple times per day;
- Carbon-reduction compensation schemes either do not exist or are insufficient to compensate investors for the additional funding.

Therefore, in the short- to mid-term, it is essential to devise markets which allow the benefits created by LDES to result in financial returns and attractive IRRs. Several market design and regulatory actions could help minimize the operational risk of commercial plants, providing visibility on revenues during the lifetime of the assets.

Optimal market designs that create the right incentive signals for long-duration services will vary by location depending on the local resources and infrastructure. For example, it may become increasingly difficult for generators and storage owners to generate an income solely from energy payments in markets with limited price volatility. These markets may need to be redesigned to compensate for flexibility, which could be accomplished through long-term capacity payments or new imbalance compensation markets. Alternatively, other markets may need to open to LDES as firm capacity and balancing providers. This could contribute to various benefits, including increased competition, increased innovation in the electric power industry, and increased grid flexibility and resilience.

Lastly, a set of requirements and drivers for LDES uptake would be desirable from a regulatory perspective. LDES technologies vary widely in maturity, safety features, and use cases, resulting in a lack of shared understanding and valuation. In addition, the role of storage in the energy system is complex, both within the power system and in conjunction with industrial end uses. Therefore, the appropriate valuation of LDES through the establishment of clear market rules is necessary. In addition, a clear definition of LDES, including minimum technical and safety requirements, would facilitate its development and implementation in the marketplace. Finally, carbon pricing mechanisms would need to be designed so that low-carbon technologies are not outcompeted for similar flexibility services by emitting assets.

Some frontrunner countries or regions have produced examples of legislation explicitly designed to meet the needs of LDES. For instance, the California bill AB 2255 (2020) proposes the adoption of a new regulatory approach as it aims to develop a process to procure and deploy GWs of LDES across the state. In addition, Arizona has launched an incentive program structured to encourage longer durations, by offering incentives for storage technologies with more than 5 hours of discharge. In the UK, there are ongoing conversations on different routes to increase profitability for LDES, including 15-year capacity markets or balancing mechanisms[34].

[34] "Facilitating the deployment of large-scale and long-duration electricity storage: call for evidence," UK Department for Business, Energy & Industrial Strategy, 2021.

Conclusion

This report has shown that Long Duration Energy Storage can play a crucial role in fully decarbonizing the power sector and thus enabling a pathway to limit the rise in global temperatures to 1.5 degrees as set out in the Paris agreement. It can provide the power system flexibility and stability required to integrate an increasing renewable share in power generation with its inherent variability, and it can do so at a manageable cost.

Data from LDES providers shows it has significant potential to become the most cost-competitive solution for energy storage beyond a duration of six to eight hours: the social benefits of large-scale deployment as solar PV and wind become the dominant sources of power are obvious.

These projections, however, come with an important caveat. They will only come to pass if action is taken in the short to medium term to create the right framework conditions for development of a market in LDES, and stimulate early investment. Large deployment is required in the next few years in order to build scale and realize the cost projections set out here. Governments need to establish a supportive ecosystem including long-term planning, economic incentives and appropriate market designs.

To be clear, this is not a proposal for an ongoing subsidy regime at the public expense: the proposed recommendations are designed to kick-start a functioning market that can support society's objective of rapid decarbonization. All the evidence suggests that this could be a highly attractive market for investors: a sizeable new industry providing 1.5 to 2.5 TW of storage capacity, requiring an investment that could reach USD 1 to 3 trillion by 2040 with potential competitive returns. The prize is within reach, and the time to seize it is now.

Appendix A: Methodology

Total addressable market (TAM) modeling

This report estimates the LDES future deployment and TAM by leveraging the McKinsey Power Model (MPM), a long-run capacity expansion model which includes elements of production cost modeling, to size deployment requirements in bulk grid applications. Additionally, the analysis augments the bulk potential with other different on-grid and off-grid applications for that are not captured by a large-scale capacity expansion model.

TAM results are sensitive to assumptions on LDES and alternatives, hence multiple sensitivity analysis have been carried out.

McKinsey Power Model

The MPM is a techno-economic optimization that simulates large-scale power systems concurrently on an hourly and multi-decadal time resolutions. It was used to determine the cost-optimal pathway to net-zero emissions across a set of real-world systems. The result is a portfolio of technologies and fuel consumption that minimize the societal cost of the transition in the modeling horizon.

A wide set of technologies ranging from traditional thermal generators such as gas turbines and nuclear power plants to technologies with increasing potential in the energy transition, such as renewables, CCS, energy storage, and power-to-fuel were included in the model. The modeling effort specifically focused on the role of LDES in the net-zero emissions transition. The result provides an outlook for the LDES market size and a possible operational profile.

Various sensitivities for technologies were defined to study the impact on the technology portfolio, and specifically, the LDES market size. The capital cost reductions of LDES technologies were defined based on the learning rate and technology commercial readiness gathered from data submissions of LDES council members. Different technology build decisions and market size restrictions, such as biomethane blending, nuclear new build restrictions, and transmission expansion restrictions, were also modeled.

The model contains bulk-transmission-level grid connections (i.e., no mid-voltage transmission or distribution grid), and within the smallest modeling region, transmission is not represented, i.e., intra-region transmission effects are not included, corresponding to a ‘copper plate’. This modeling limitation will necessarily underestimate the market size of LDES since transmission constraints, which LDES can provide a strong value proposition to mitigating, are not fully considered. In addition, the model only covers the power sector as well as fuel creation related to supply predefined demand from the power sector, e.g., such as hydrogen production. No co-optimizations on other sectors such as dual fuel boilers, space heating co-optimization or global clean fuels flows were considered. These aspects could be considered in future analysis to further understand the potential of LDES.

Non-MPM TAM estimates

As a parallel effort, additional sizing outside the MPM was performed, estimating the LDES market size in off-grid applications, and the value created by LDES in use cases not considered by MPM. Five additional value streams have been defined and assessed: optimization of transmission and distribution investment, stability services provision, firming for PPAs, isolated island grid optimization, and energy for industries with remote or unreliable grid.

In the optimization of transmission and distribution case, the generation capacity support of LDES is already accounted for in the MPM results while optimal geospatial placement of deployed LDES would provide additional value creation, which has been separately sized. The value refers to the savings in transmission and distribution infrastructure investments, sized by assessing the potential of LDES to increase the grid utilization, therefore reducing buildout requirements, while not impacting system reliability. The methodology was followed in detail for two countries, the US and Germany, before extrapolating the figures to a global value.

Several different approaches were used to size the deployment of LDES in remote and unreliable grids. For remote mines a hybrid model was deployed in a method analogous to islanded power grids in a Chilean copper mine, with the McKinsey MineSpans database used to identify the electrical energy requirements of suitable mines globally. For unreliable grids, sectoral energy demand with requirements for high uptime (e.g., chemicals, manufacturing, metal processing) were identified in countries with high historical records of blackouts. The total storage requirement to bridge blackout periods was calculated and an LDES penetration was assumed to estimate the deployed systems. A value equivalent was attributed to the productivity of avoided downtime. For critical on-grid assets using RE (e.g., military bases and hospitals), only the LDES energy capacity deployment was included (the expectation is that LDES will be used for more than backup purposes); however, additional value was estimated with the removal of backup diesel generation.

LDES deployment and value of island grids was based on in-depth hybrid energy system modeling using real hourly supply/demand load profiles of the O'ahu island system in Hawaii to determine the optimum decarbonized energy setup across RE options, Li-ion, and LDES overtime. This produced a deployment of LDES per GWh consumed annually and value savings based on reduced production costs, stability services, and CO_2e reductions. This result was then scaled to cover global isolated island grids. This was done by identifying all islands with 0.1 million to 5.0 million inhabitants, then filtering those based on mainland grid connections and other common-sense checks (e.g., removing highly populated Indonesian islands that would be double counted with the main MPM modeling) before a moderation of storage need was conducted based on RE potential in each county. Finally, the result was scaled using the annual energy consumption of each island.

Sizing of LDES requirements for corporate RE PPAs was taken using forecasts for RE PPAs globally based on historical trends, understanding what proportion would require near 100 percent 24/7 RE coverage and assuming a level of LDES penetration (versus Li-ion or other firming options). To calculate the value of these deployments, the cost of covering any non-RE power consumption with the purchase of RE guarantees of origin and carbon credits was calculated. New deployments and value from RE PPAs were assumed to reach a peak in 2030 before being phased out as general grids reach high proportions of firmed RE.

The opportunity for stability services was also modeled focusing on inertia provision (as likely the most significant service). It was reasoned that LDES would not be economically installed purely for inertia provision, so modeling focused on identifying the additional value that could be achieved should these services be monetized. To do this, a method for the next lowest-cost alternative was implemented using the cost of installing synchronous condensers from various real quotations, and scaling for the installed quantity of LDES in a region from the MPM results.

LCOS modeling

The LCOS represents the discounted total unit cost of ownership of storage technology over the project lifetime. This metric accounts for all technical and economic parameters impacting the lifetime cost of discharging stored electricity. It is directly comparable to the LCOE for generation technologies and represents an appropriate tool for cost comparison of electricity storage technologies. However, LCOS for storage, much like LCOE for dispatchable generators, is not an intrinsic property of the installed technology, but depends heavily on the operations of the system. As such it is extremely useful in comparing costs, but the user should understand input parameters and limitations of the comparison. Modeling deeply decarbonized systems is a complex task, and metrics such as LCOE and LCOS provide a baseline to orient market participants to the relevant technologies. Exhibit 35 reports the LCOS formula, showing its components.

The LCOS must be handled carefully to create meaningful results. Successful LCOS use cases appear in well-defined storage demand and well-understood technology behavior, like daily energy arbitrage markets. These

Exhibit 35

LCOS formula

Computation of the levelized cost of storage (LCOS)

- Capex of LDES solution, construction, balance of system

- O&M costs
- Replacement intervals and costs

- Round-trip efficiency (RTE)
- Ancillary consumption, self-discharge
- Cost of charging energy

$$\textbf{LCOS} = \frac{\textbf{Installation cost} + \textbf{lifetime discounted O\&M cost} + \textbf{lifetime discounted charging cost}}{\textbf{Total lifetime discounted electricity discharged}}$$

Used throughout

- Discount rate
- Nameplate capacity
- Depth of discharge
- Duration, unit energy costs
- Annual degradation rate
- Annual and lifetime cycle count

factors imply consistent utilization profiles that produce sensible LCOS comparisons. Poor use cases are defined by occasional or sporadic storage demand, like utility reliability markets or integrating multiple revenue streams and storage uses. For these sporadic use cases with sparse cycle counts, LDES solutions are better compared to capex or annuitized capacity costs and not LCOS since efficiencies and replacement costs are less important.

The main assumptions are:

- Annual LDES asset utilization: 45 percent in all durations. This value represents the portion of time the storage is either charging or discharging. It was inferred as an outcome of the MPM and chosen as the base case.
- Average lifetime charging cost: 30 USD/MWh
- Hydrogen turbine costs: they are based on findings from the Hydrogen Council[35] and latest academic literature figures. Assumptions on the cost of hydrogen in 2030 are key in determining the two different scenarios (2 USD per kg in the central scenario and 1 USD per kg in the progressive scenario). Relying on the academic and industry consensus on peaking plants utilization values, a capacity factor of 15 percent for the turbine was assumed.
- LDES energy and power capacity, and charging rate: the energy and power capacity values are system nameplate capacities. 100 MW was the chosen nameplate power capacity for the different systems compared. The charge and discharge limitations are accounted in the depth of discharge metric, which is defined as effective dischargeable energy capacity over nominal energy capacity (considering both charging and discharging limitations). Only nominal charging rates have been considered (i.e., 1C charging rate for Li-ion).
- Li-ion costs: the progressive and central scenarios are based on the McKinsey Battery Cost Model. The central scenario implies a cost improvement learning curve projections without considering disruptive Li-ion technology breakthroughs, while the progressive scenario anticipates aggressive component cost improvements. The assumed Li-Ion and hydrogen cost and performance trajectories are amongst the most progressive from their sources.
- WACC: 6 percent

[35] Hydrogen Insights, 2021

Carbon cost trajectories

CO_2 costs differ heavily by region and will have different development trajectories influenced by policies and regulation at national and international level. The MPM sets specific emission reduction targets rather than assumed CO_2 cost trajectories.

CO_2 costs outlooks have been accounted in the modeled business cases, where three scenarios have been defined: base (60 USD/tCO_2e in 2030), medium (75 USD/tCO_2e in 2030) and high scenario (100 USD/tCO_2e in 2030). All scenarios assume a 8 percent compound annual growth rate over the period from 2030 to 2040.

Currency

All financial figures are in 2020 US dollars (USD) and refer to global averages unless otherwise indicated.

Appendix B: Examples of business cases

1. RE developer in Australia

The business case for RE developers or owners looking to increase the firming of RE PPAs with LDES systems could be attractive in the short term

According to the Australian Clean Energy Council, tenders for RE corporate PPAs with firmed capacity are expected to grow in Australia. They enable customers to achieve environmental, social, and corporate governance targets and hedge market volatilities. In addition to upcoming RE needs from end consumers, grid systems are experiencing increasing challenges in bringing RE capacity online.

For example, on average, 5 percent of solar and wind power was curtailed in Queensland, Australia, since 2019, putting pressure on RE developers' financials. These curtailment levels are likely to increase to double-digit percentages in the next decade, as seen in countries with higher RE penetration. In addition, stability issues will become more pronounced as conventional generation plants (such as coal and eventually natural gas) are phased out.

Given this context, a deployed LDES system can participate in multiple value streams. Here the case of a RE developer deploying LDES for RE PPA firming with a front-of-the-meter contract, whilst providing services to system operators is explored. (Exhibit 36)

Exhibit 36

Australia renewables developer case example, net present value

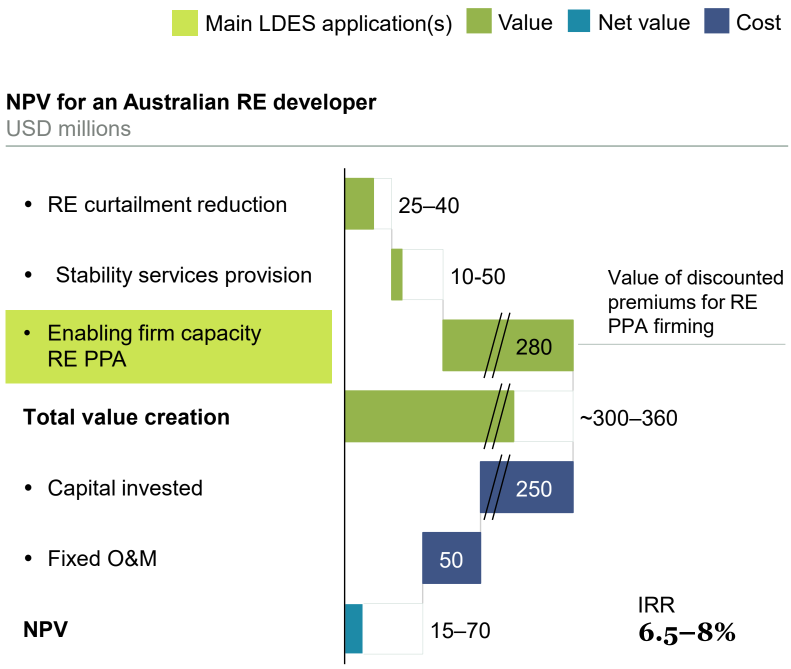
Customer profile

RE developer in Australia providing RE for corporate PPAs

Increasing corporate demand for near 100% RE to meet decarbonization targets

LDES asset enables firming of the RE PPA; additionally, system can provide ancillary services

Potential LDES system: 150 MW/1200 MWh (8 hours); systems of longer durations would be required in locations with lower annual RE yield



Assumptions	*Final investment decision date*	*Commercial operation date*	*CO_2e price scenario*	*WACC*
	2023	*2025*	*Base case*	*6%*

The case example shows an IRR of approximately 6.5 to 8 percent, indicating short-term financial attractiveness. In this case, the most significant value stream is created by enabling firm capacity for a RE PPA and has a present value of about USD 280 million, indicating regional PPA price indexes have a considerable influence on the case profitability.

The reduction of RE curtailment and provision of stability services contribute to a lesser extent, with current values of approximately USD 25 million and USD 10 million, which could potentially increase to around USD 40 million and USD 50 million respectively due to increase curtailed RE volumes and regulation of stability services such as inertia provision. (Exhibit 37)

In addition to the project starting date, three sensitivities influence the project IRRs. The IRR increases significantly to approximately 14 percent for the base case when the commercial operation date moves to 2030, with the construction of the system taking place two years prior. However, it is more common to have shorter rather than longer contract durations, with shorter RE PPA contract terms resulting in 1 to 2 percentage point lower, making the IRR fall below the weighted average cost of capital (WACC).

Several steps could help unlock additional value potential—for example, creating market mechanisms that enable RE developers to access different value streams outside the market for energy shifting such as inertia provision. Another option would be increasing certainty on accessible value through regulatory schemes that make it more attractive for corporate customers to engage in long-term contracting. The NPV could also increase if the WACC is lowered through different existing and innovative financial instruments, including insurance for energy storage and public–private regulatory options.

Exhibit 37

Australia RE developer case example, IRRs

IRR sensitivity to contract durations and project start date[1]

Base case | <5% | 5–10% | 10–15% | 15–20% | >20%

		Commercial operation date: 2025	Commercial operation date: 2030
Curtailment volumes % of energy output curtailed	20	7.5%	15%
	15	7%	14.5%
	10	6.5%	14%
Ancillary services revenues USD millions annually	3.75	8%	16%
	2.25	7.5%	15%
	0.75	6.5%	14%
PPA contract duration[2] Years	20	6.5%	14%
	15	6%	13.5%
	10	4.5%	12.5%

1. Lower end of range for value capture in markets with appropriate mechanisms; higher end of range for full value potential.
2. After contract end, value of service ~50% of in-contract value.

2. Isolated island integrated utility in the US

The near-term financial viability of LDES for integrated utilities on isolated power systems with limited interconnectivity depends on local fuel costs and RE potential

Off the mainland, the US has multiple islands that have no connection to neighboring islands or the mainland grid. Hence, they are mainly dependent on coal and fuel-oil-generated power. The electricity cost for consumers on these islands is among the highest in the US.[36] At the same time, there is considerable potential for low-cost RE generation. These conditions have already led to a buildout of solar and wind capacity, increasing the share of RE in the generation mix. With the growing decarbonization of the island's power system, thermal generation will be decommissioned and stability services reduced.

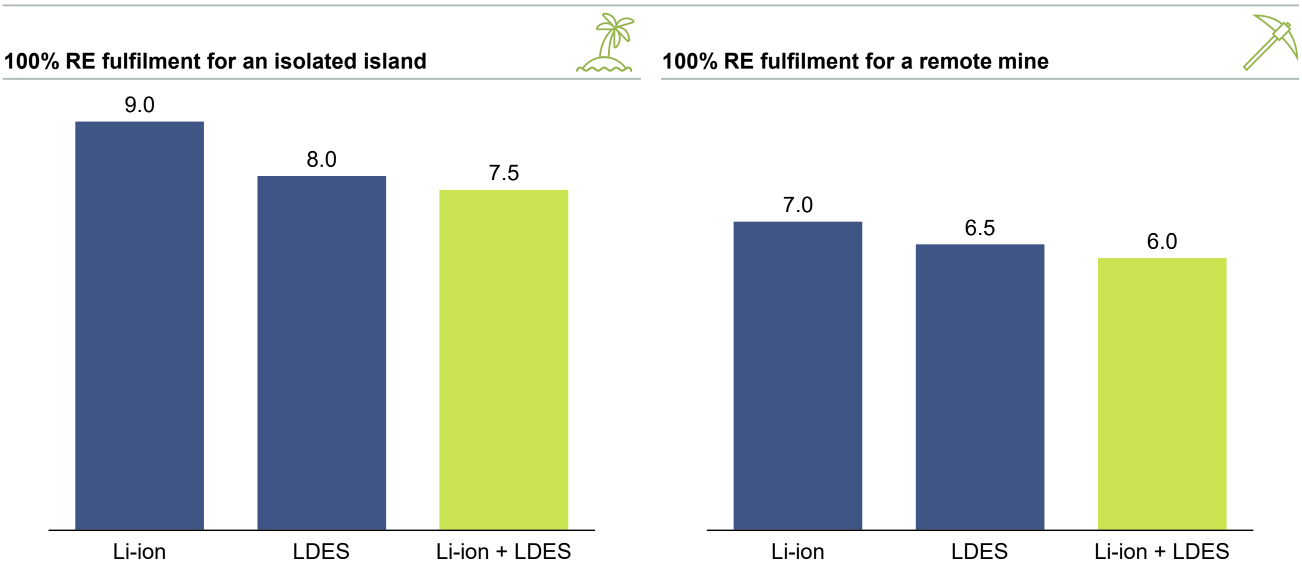
To achieve full power decarbonization on such an island, the incumbent integrated utility could install a hybrid of additional solar and wind with Li-ion batteries and LDES. Detailed modeling of an isolated island system indicates that the lowest cost pathway to 100 percent fulfillment of energy demand by RE employs a combination of Li-ion and LDES. The LCOE of this configuration is 15 percent lower than a pure Li-ion battery system—caused by the significant RE overbuild—and 5 percent lower than a pure LDES system. (Exhibit 38)

The deployment of such a RE hybrid storage system could take place in a multi-phase buildout. It is here assumed that 40 percent of energy demand is fulfilled by the existing build-out of RE without storage. The costs and benefits of this pre-deployment phase are not included in the assessment of the business case. In the first phase of the deployment additional RE capacity and Li-ion battery capacity to achieve 70 percent RE fulfilment. In the second phase, additional RE capacity, Li-ion battery capacity, and the LDES system would be constructed to achieve 100 percent RE fulfilment by 2030. (Exhibit 39)

Exhibit 38

Cost comparison of different storage options for decarbonizing electricity on an isolated island and a remote mine

LCOS in 2040 for different storage mixes in a RE hybrid system
cents of USD per kWh



Key assumptions: Top-quartile LDES 24+ hour archetype cost figures, conservative learning rates.

[36] "Electric power annual", Energy Information Administration, 2019.

Exhibit 39

Integrated utility on an isolated US island, net present value

Main LDES application(s) | Value | Net value | Cost | Accessible value with market mechanisms in place

Customer profile

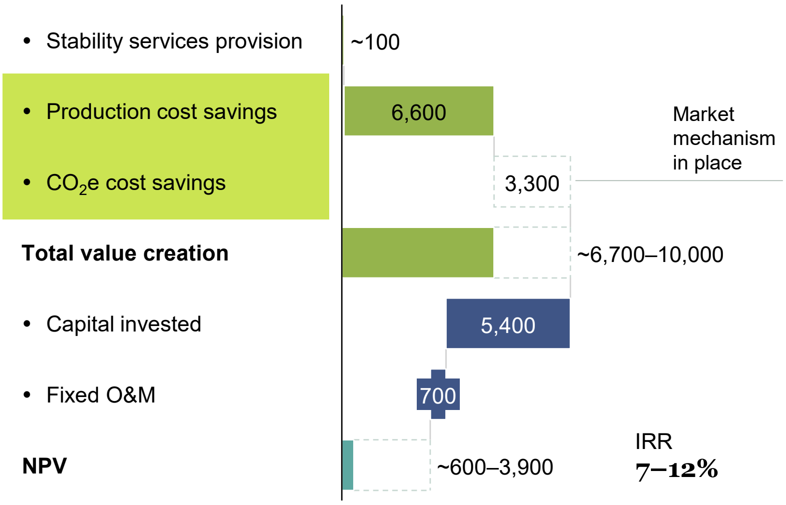
Integrated utility on a US island without interconnection to the mainland

Relies on carbon-intensive electricity generation sources

Step-wise build-out of RE and storage, incl Li-ion and LDES, through a realistic low-cost scenario

Potential LDES system: 1.3 GW/104 GWh (80 hours)

NPV for an integrated utility on an isolated US island
USD millions



Assumptions	*Final investment decision date*	*Commercial operation date*	*CO_2e price scenario*	*WACC*
	2023 (RE and Li-ion) *2028 (RE, Li-ion and LDES)*	*2025 (RE and Li-ion)* *2030 (RE, Li-ion and LDES)*	*Base case*	*6%*

The resulting IRR of this case example is 7 to 12 percent, with an NPV of USD 500 million to USD 3.9 billion. The results imply that for some situations, the business case will be “in the money” and potentially attractive for investors, strongly driven by fuel costs and RE potential. However, for other instances with a gap to viability, it is vital to ensure the value capture of CO_2e cost savings.

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The main value streams from the RE hybrid storage system are production cost savings and CO_2e cost savings, which have projected present values of approximately USD 6.6 billion and USD 3.3 billion, respectively.

Multiple sensitivities materially influence the financial viability of this case, namely shifted operation dates, CO_2e price, fuel costs, and RE capex. The IRR increases significantly to between 11 and 17 percent when the LDES commercial operation date moves to 2035, with the construction of the system taking place in the two years prior. Furthermore, accelerated CO_2e price increases could result in IRRs of 15 and 20 percent, with LDES operation dates by 2030 and 2035, respectively. However, the IRR would significantly drop in islands with lower fuel costs or less advantaged RE potential. A fuel cost USD 50 per MWh lower than the base would reduce the IRR by approximately 3 percent. A similar effect occurs when RE capex increases by 50 percent. (Exhibit 40)

To ensure the financial viability of LDES for integrated utilities on isolated islands, multiple actions could be considered. These actions include creating market mechanisms for CO_2e benefit remuneration, providing options to lower WACC, ensuring CO_2e price stability, and facilitating the traceability of energy for LDES charging.

Exhibit 40

Integrated utility on an isolated US island, IRRs

IRR sensitivity to contract durations and project start date[1]

Base case | <5% | 5–10% | 10–15% | 15–20% | >20%

		Commercial operation date: 2030	Commercial operation date: 2035
CO_2e price scenario 2030 USD/ tCO_2e	**High** 100	7–15%	11–20%
	Medium 75	7–13%	11–19%
	Base 60	7–12%	11–17%
Fossil fuel cost USD/ MWh	200	11–16%	17–22%
	150	7–12%	11–17%
	100	3–9%	5–13%
RE capex sensitivity % increase	0	7–12%	11–17%
	50	5–10%	8–14%
	100	4–9%	6–11%

1. Lower end of range for value capture in markets with appropriate mechanisms; higher end of range for full value potential.

3. Remote copper mine in Chile

For an industrial customer looking to reduce electricity production costs and decrease their carbon footprint, deploying LDES could be financially attractive in the near term

A mining company operating a remote Chilean copper mine currently relies on onsite diesel generators for a stable electricity supply. The resulting electricity costs represent 10 percent of the total mining and processing costs. Reliability of the onsite electricity system is also critical because of the high opportunity costs of power outages (12 hours of power outages a year would translate into USD 1.5 million in lost revenue). (Exhibit 41)

Increasing cost pressure, together with decarbonization ambitions and reducing renewable LCOEs, pushes the company to consider switching to RE and, subsequently, storage to ensure fully RE generation.

Like the isolated island integrated utility, the mining company could consider installing a hybrid of additional solar and wind with Li-ion batteries and LDES. This hybrid configuration allows the mining company to reduce production costs—relative to their onsite diesel generation—and related CO_2e emission costs.

Detailed modeling of a RE hybrid storage system for the mine indicates that the lowest cost pathway to 100 percent fulfillment of energy demand via RE employs a combination of Li-ion and LDES. The LCOE of this configuration is 10 to 15 percent lower than a pure Li-ion battery system and 5 percent lower than a pure LDES system.

The deployment of the RE hybrid storage system could take place in a multiphase buildout, similar to the isolated island system.

The resulting IRR of this example is 15 to 19 percent, with an NPV of USD 1.5 billion to 2.7 billion, indicating that this type of LDES application as part of RE hybrid storage systems can be "in the money" in the near term.

Further acceleration of investments could be driven by rising ambition levels of corporate decarbonization targets.

Exhibit 41

Remote Chilean copper mine case example, net present value

Main LDES application(s) | Value | Net value | Cost | Accessible value with market mechanisms in place

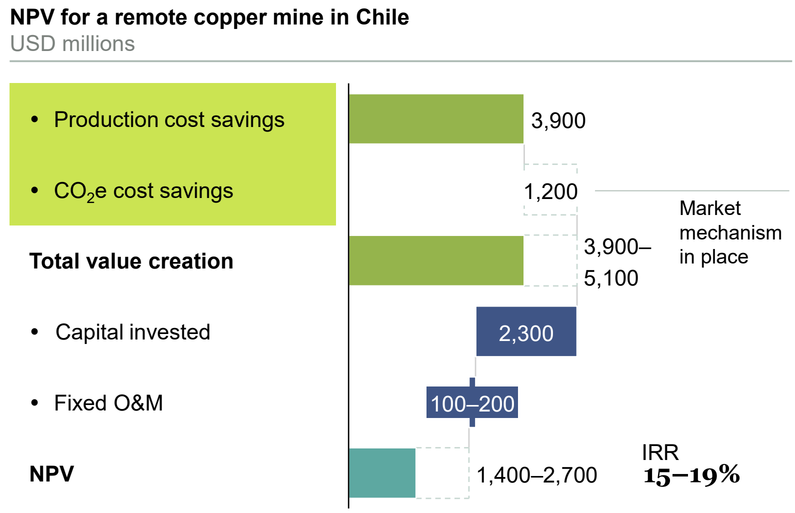
Customer profile

Mining company operating a remote copper mine in Chile

High electricity costs with current power supply from diesel generators

Step-wise build-out of RE and storage, incl Li-ion and LDES, through a realistic low-cost scenario

Potential LDES system: 0.7 GW/56 GWh (84 hours)



Assumptions	*Final investment decision date*	*Commercial operation date*	*CO_2e price scenario*	*WACC*
	2023 (RE and Li-ion) *2028 (RE, Li-ion and LDES)*	*2025 (RE and Li-ion)* *2030 (RE, Li-ion and LDES)*	*Base case*	*6%*

The main value streams from the RE hybrid storage system are production cost savings and CO_2e cost savings, which have projected values of approximately USD 3,900 million and USD 1,200 million, respectively. Also here, monetization of CO_2e cost savings requires an adequate market mechanism. (Exhibit 42)

Like the isolated island situation, a range of sensitivities on IRRs have been evaluated, particularly a shifted operation date, CO_2e price, fuel cost, and RE capex. A shift in the LDES component commercial operation date to 2035 considerably increases the IRR between 19 and 23 percent. In addition, accelerated CO_2e price increases could result in IRRs of up to 21 and 26 percent, with LDES operation dates by 2030 and 2035, respectively. For mines with simpler fuel logistics and lower RE potential, the IRR could drop by 3 percent, for example, due to a USD 50 per MWh lower fuel cost than the base case or a RE capex increase of 50 percent. However, the IRR would still be significantly above the WACC of 8 percent, indicating a more robust business case for this application.

Exhibit 42

Remote Chilean copper mine case example, IRRs

IRR sensitivity to contract durations and project start date[1]

Base case | <5% | 5–10% | 10–15% | 15–20% | >20%

		Commercial operation date: 2030	Commercial operation date: 2035
CO_2e price scenario 2030 USD/tCO_2e	**High** 100	15–21%	19–26%
	Medium 75	15–20%	19–24%
	Base 60	15–19% (base case)	19–23%
Fossil fuel cost USD/MWh	300	19–22%	23–27%
	250	15–19% (base case)	19–23%
	200	12–16%	14–19%
RE capex sensitivity % increase	0	15–19% (base case)	19–23%
	50	14–17%	16–21%
	100	12–16%	15–19%

1. Lower end of range for value capture in markets with appropriate mechanisms; higher end of range for full value potential.

4. On-demand RE peak power in India

The business case for a RE developer in India providing peak and off-peak supply with a combination of RE and PSH could show attractive IRRs and more competitive PPA tariffs than fossil generation procurement

Decarbonizing India's power supply requires the widespread deployment of flexibility solutions such as LDES. Electricity demand is expected to rise sharply as more end-uses, such as heating and transportation, electrify, renewable hydrogen production expands, and living standards increase. In 2020, nearly 70 percent of India's power generation mix was thermal, with coal accounting for 85 percent. With more than 75 GW of installed capacity, RE accounted for nearly 20 percent of the mix, with solar seeing the fastest growth. At the Glasgow climate change conference, India committed to reach 500 GW of non-fossil generation capacity by 2030, representing a nearly 500 percent increase over current RE levels. Hence, meeting this target while supplying the increased demand and managing the grid stability is expected to require the deployment of innovative solutions and flexibility resources like LDES.

Given this context, a deployed LDES system can provide different services. This case explores a RE developer deploying LDES to enable dispatchable RE with a front-of-the-meter contract. Specifically, a business case of LDES to enable dispatchable peaking capacity within specific contracted hours of the day, is modelled. A 6-hour system is considered given its suitability to a solar generation profile (solar PV is expected to be increasingly deployed in India in the near term). The 300 MW and 1,800 MWh novel PSH system is assessed in combination with 600 MW of hybrid solar PV and wind capacity. (Exhibit 43)

The case example shows an IRR of approximately 10 to 12 percent, indicating short-term financial attractiveness for potential infrastructure investors. Peak power supply shows a present value of about USD 700–800

Exhibit 43

India RE developer case example

Main LDES application(s) | Value | Net value | Cost | Accessible value with market mechanisms in place

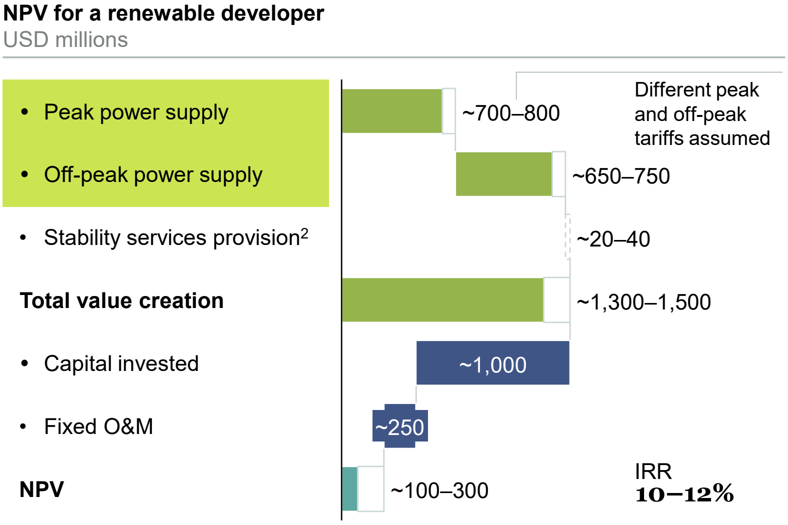
Customer profile

RE developer in India providing morning and evening peak supply as well as off-peak generation with a combination of RE and PSH

Providing lower cost PPA tariffs compared to the case of procurement from thermal power[1]

LDES asset (ie, PSH) enables dispatchable peaking capacity

Modeled LDES configuration: 300 MW/1800 MWh (6 hours); in combination with 600 MW of contracted hybrid RE[1] (solar and/or wind)



Assumptions	*Final investment decision date*	*Commercial operation date*	*WACC*	*RE cost outlook*	*PPA contract duration*
	2021	*2023*	*10%*	*Progressive[3]*	*20 years[4]*

1. Corresponding to ~870 MW of DC installed capacity
2. Inertia provided by the PSH, remuneration based on NGESO's Stability Pathfinder mechanism
3. Capex figure for PSH takes an industry estimate for off-stream closed-loop systems in India and NREL-ATB Advanced costs for RE
4. After contract end, value of service ~50% of in-contract value

million, while off-peak power generation contributes to a comparable extent, with NPV values approximately between USD 650 million and USD 750 million. The revenues streams are similar as the higher PPA tariff during peak periods is balanced by a smaller yearly energy supply (around one third of the total generation).

Market remuneration of inertia for power system stability is not a currently existing value stream in India, but could be worth about USD 20-40 million alone with similar mechanisms under implementation in other countries. (Exhibit 44)

Both the project starting date and the LDES storage CAPEX influence the project IRR. The IRR increases significantly to approximately 22 to 25 percent for the base case when the commercial operation date moves to 2030, with the construction of the system taking place two years prior. This behavior is explained by the high value of storage solution in the next decade, able to mitigate higher price peaks and larger electricity spreads caused by a higher RE penetration. The value of green dispatchable PPA contracts will increase in value in the upcoming decade, heavily contributing to the profitability of this business case. Furthermore, novel PSH systems costs in India could see a more rapid cost down trajectory, enabling significantly higher returns than in other regions.

Several factors could help unlock additional value potential—for example, an increased spread of electricity prices leading to more valuable PPA contracts, increased demand for clean peaking dispatchable power, or sustained long contract durations as penetration of renewable increases.

Exhibit 44

India RE developer case example, IRRs

IRR sensitivity to contract duration and project start date

Base case <5% 5–10% 10–15% 15–20% >20%

LDES storage CAPEX[1]	2023	2027	2030
Progressive	10–12%	14–16%	22–25%
Central	9–11%	13–15%	20–22%
Conservative	6–8%	9–11%	13–15%

Commercial operation date

1. India industry costs perspective