

Advanced and Long-Duration Energy Storage: A Review of Emerging Technologies, Applications, and Techno-Economic Assessment

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Case Report

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Advanced and Long-Duration Energy Storage: A Review of Emerging Technologies, Applications, and Techno-Economic Assessment

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ARTICLE INFO	ABSTRACT
<i>Keywords:</i> Long-duration energy storage Levelised cost of storage Pumped hydro Compressed air Flow batteries Iron-air battery Thermal storage Hydrogen Grid reliability <i>Article type:</i> Review paper (academic) <i>Prepared:</i> October 2026	Variable wind and solar generation have pushed the power sector from a question of capacity to a question of duration. Battery storage added a record 108 GW worldwide in 2025, about 40% more than in 2024, yet the average project still discharges for only about three hours [1,22]. This review examines what lies beyond that horizon. It integrates agency data (IEA, IHA, Lazard), peer-reviewed techno-economic reviews and project disclosures to cover (i) the physics and maturity of long-duration and advanced storage technologies, namely pumped hydro, compressed and liquid air, flow batteries, iron-air and sodium-ion batteries, thermal storage and hydrogen; (ii) their grid and industrial applications; and (iii) a transparent techno-economic assessment. Three original analyses prepared by the author are presented: a levelised-cost-of-storage (LCOS) model across eight technologies, a sensitivity analysis, and a 14-day dispatch simulation of a wind and solar system with a four-day wind lull. Under the stated assumptions, lithium-ion is cheapest only up to about 2 to 3 hours; at 24 h its LCOS is about US\$385/MWh against about US\$142/MWh for adiabatic compressed air, and at 100 h the gap widens to roughly 6 times. In the simulation, adding the first 4 h of storage raises the share of demand served from 70% to 83%, while closing the remaining gap needs about 100 h. A chemical-engineering perspective on electrochemistry, thermodynamics and materials is added, and the Indian context is examined in detail, where the planning requirement of 411 GWh by 2031-32 contrasts with 0.7 GWh of battery storage operating in 2025 [9,10].

1. Introduction

Decarbonised power systems are built around wind and solar, whose output follows the weather rather than demand. For the first decades of that transition, short-duration batteries were enough: they absorb midday solar and release it in the evening. The data now show how quickly that niche has become mainstream. The IEA reports that battery storage capacity additions reached 108 GW in 2025, about 40% above 2024 and more than the highest annual addition ever recorded for gas-fired plants, and that installed battery capacity is now eleven times its 2021 level [1,22]. Costs fell by more than 90% between 2010 and 2025, and lithium iron phosphate (LFP) chemistry accounts for roughly 90% of deployments [1,22].

The same data show the limit of this success. More than 90% of new battery projects now target energy shifting rather than short ancillary services, and the average project duration has risen only from two hours in 2023 to three hours in 2025 [22]. A grid with a large share of wind and solar faces events that last longer than that: multi-day wind lulls, cloudy winter weeks and seasonal imbalances between supply and demand. Lazard's 2025 analysis notes that firming costs rise with the share of intermittent generation and that, in California, higher solar penetration has already lowered the effective capacity credit of four-hour storage [3]. Long-duration energy storage (LDES) is the response to this problem, but it is not one technology. It spans a century-old mechanical technology, pumped hydro, which supplies the great majority of stored energy today [2], and a group of emerging options in mechanical, electrochemical, thermal and chemical storage that are only now reaching their first commercial plants.

Several recent reviews examine parts of this field. Aspitarte and Woodside survey 376 storage media and conclude that lithium-ion batteries and pumped hydro do not look promising for multi-day and seasonal use on the basis of energy capital cost [4]; a review of hydrogen-based LDES covers production, storage, reconversion and digital optimisation [5]; a techno-economic assessment for Australia stresses that suitability is strongly site-dependent [6]; and a UK network study found molten-salt and adiabatic compressed air storage most cost-effective for longer durations [7]. This paper synthesises these works with current market and project data, and contributes the following:

- a duration-based framework linking technologies, applications and policy (Section 2);
- comparative tables of technologies, evidence levels, applications, policies and challenges;
- original quantitative analyses: an LCOS model with sensitivity analysis, and a dispatch simulation showing how much duration a wind-and-solar system needs (Sections 6 and 7);
- a chemical-engineering perspective on electrochemistry, thermodynamics and materials (Section 8); and
- a detailed look at India, where storage planning, tendering and operation are at very different stages (Section 9).

2. Review methodology and framework

The review followed the five stages in Fig. 1. Keywords (long-duration energy storage, LCOS, pumped hydro, compressed air, flow battery, iron-air, thermal storage, hydrogen storage) defined the scope. Peer-reviewed techno-economic reviews and assessments [4-8] formed the analytical base. Market and capacity statistics were taken from agency sources (IEA [1,22], IHA [2], Lazard [3], India Energy Storage Alliance [10], Central Electricity Authority [9]) and project facts from developer and trade-press disclosures [12-21]. Because many of the newest technologies have few independent measurements, key performance figures are tagged by evidence level in Table 4 (independent, regulator or agency, or developer claim), and claims from developers are reported as claims.

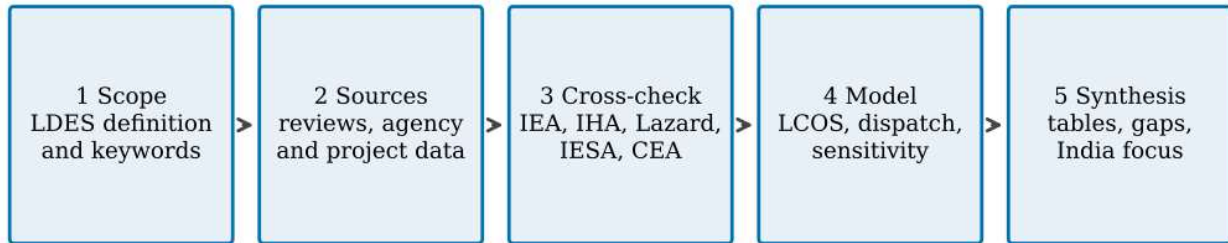


Fig. 1. Methodology of the present review.

2.1. Positioning against earlier reviews

Table 1 summarises the main sources and what this paper adds. The common limitation is that each source treats one technology family, one region or one cost metric. None combines a cross-technology cost model with a system-level dispatch test, and none connects the global technology picture to the Indian planning requirement.

Table 1 Scope of the core review sources and the contribution of this paper.

Source	Main focus	Limitation addressed here
Aspitarte and Woodside [4] (2024)	Energy capital cost floor of 376 storage media	Material-level only; no system, dispatch or LCOS view
Hydrogen LDES review [5]	Hydrogen routes, integration, digital twins	Single technology family
Australia assessment [6] (2025)	11 technical parameters, LCOS, 4 environmental criteria	Single-region, site-specific conclusions
UK LDES NODE report [7]	Cost of LDES for network use	UK context; cost ranking only
LCOS literature review [8] (2024)	Meta-review of LCOS studies	High heterogeneity between studies; no dispatch test
This paper	Technologies + applications + LCOS + dispatch + India	Integrated view with original model and charts

2.2. What counts as long duration

Storage duration is the time a system can discharge at rated power before it is empty, $D = E/P$, where E is usable energy capacity and P is power capacity. Lithium-ion systems typically operate at 1 to 4 h and are the benchmark against which LDES is defined. In this paper, "long-duration" means 8 h or more, "multi-day" means 24 h or more, and "seasonal" means weeks to months. Fig. 2 places the technologies on this axis. The classes matter because each duration requires a different cost structure: for short durations, power cost (US\$/kW) dominates, while for long durations, energy cost (US\$/kWh) of the storage medium dominates. This is the central point of the media survey by Aspitarte and Woodside, and it is why a technology that is excellent at four hours can be uneconomic at forty [4].

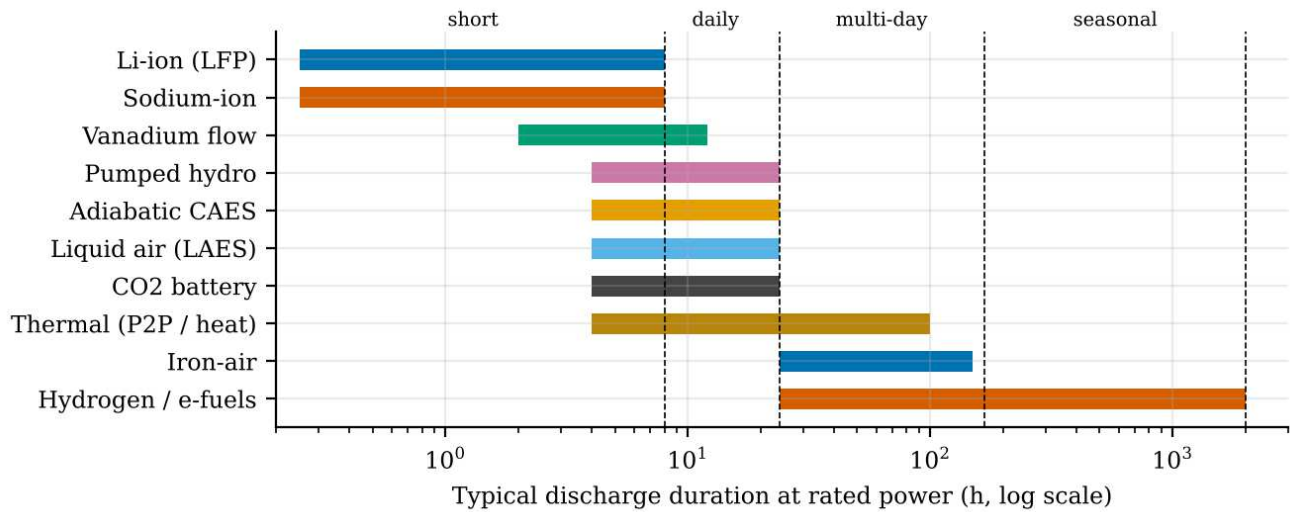


Fig. 2. Typical discharge-duration ranges of storage technologies at rated power (log scale). Ranges are the author's synthesis of [2,3,4,7,14-21] and represent commercial or demonstrated configurations rather than physical limits.

3. Global status of energy storage

Table 2 lists headline indicators and Fig. 3 shows the growth in battery additions. Battery capacity additions of 108 GW in 2025 were about 40% above 2024, implying roughly 77 GW in 2024, and the installed base is eleven times its 2021 level, implying about 10 GW added in 2021 (both derived here from the IEA ratios [1,22]). China accounted for about 63 GW, nearly 60% of the total, followed by the United States (about 19 GW), Australia (nearly 8 GW, almost nine times its 2024 level) and Europe (about 6.2 GW) [22,1]. Utility-scale projects were about 80% of additions, and behind-the-meter capacity also grew [1]. Battery-based UPS capacity, mainly in data centres, rose 30% to 45 GW [1]. In Australia, batteries already make up about 18% of dispatchable capacity, compared with 7% in China, 5% in the United States and 4% in Europe, and California has grown from under 1 GW in 2019 to over 17 GW [22].

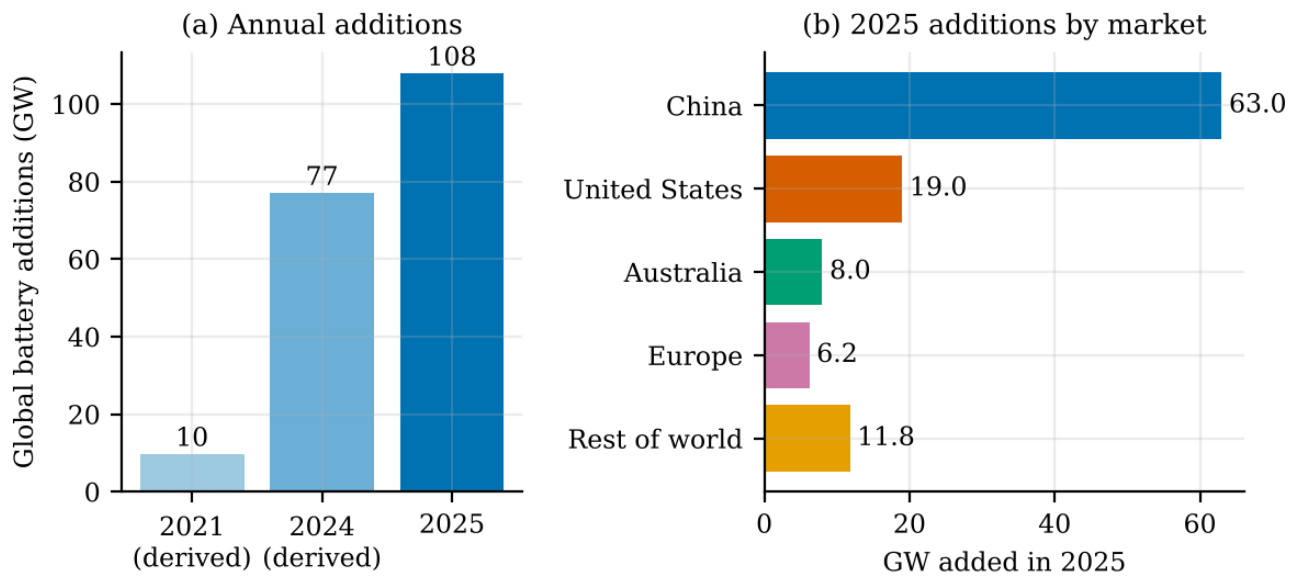


Fig. 3. Battery storage additions: (a) global annual additions, with 2021 and 2024 derived from the IEA ratios (eleven-fold growth since 2021, +40% in 2025); (b) 2025 additions by market. Source: IEA [1,22]; "rest of world" is the remainder.

Table 2 Snapshot of global storage indicators (2024-2025).

Indicator	Value	Source
Global battery additions, 2025	108 GW (+40% on 2024); 11x installed capacity of 2021	[1,22]
Utility-scale share of 2025 additions	About 80%	[1]
Battery cost reduction, 2010 to 2025	More than 90%	[1,22]
Share of LFP in deployments	About 90%	[1]
Average battery project duration	3 h in 2025 (2 h in 2023)	[22]
Pumped hydro installed capacity, end-2024	189 GW (+8.4 GW in 2024)	[2]
Pumped hydro development pipeline	About 600 GW	[2]
Pumped hydro share of stored energy	More than 90% of all long-duration storage	[2]

Indicator	Value	Source
Lazard LCOS, 100 MW 4 h utility BESS (US)	US\$115 to 254/MWh (2 h: US\$129 to 277/MWh)	[3]

Pumped storage hydropower remains the backbone of long-duration storage. The International Hydropower Association reports 189 GW installed at the end of 2024 after 8.4 GW of additions, a pipeline of about 600 GW, and the claim that pumped hydro provides more than 90% of all stored energy worldwide [2]. China added 7.75 GW of pumped hydro in 2024 and is on track for its 120 GW target by 2030, and Europe has a 52.9 GW pipeline [2]. Beyond pumped hydro, the first commercial-scale plants of newer technologies are now operating or being built (Fig. 4). The largest are in China: the 2.4 GWh Huai'an adiabatic compressed-air plant (two 300 MW units, a stated 71% conversion efficiency from the equipment supplier) [15], the 60 MW/300 MWh Jintan salt-cavern plant with a reported round-trip efficiency above 60% [15], and vanadium flow batteries of 400 MWh (Dalian, phase 1) and 700 MWh (Xinhua Ushi) [17]. Outside China, plants such as Highview Power's 300 MWh liquid-air facility in the UK [18], Energy Dome's 200 MWh CO₂ battery in Sardinia [16], Rondo Energy's 100 MWh heat battery [19] and Form Energy's 150 MWh iron-air project in Minnesota [14] mark the move from pilot to first commercial deployment.

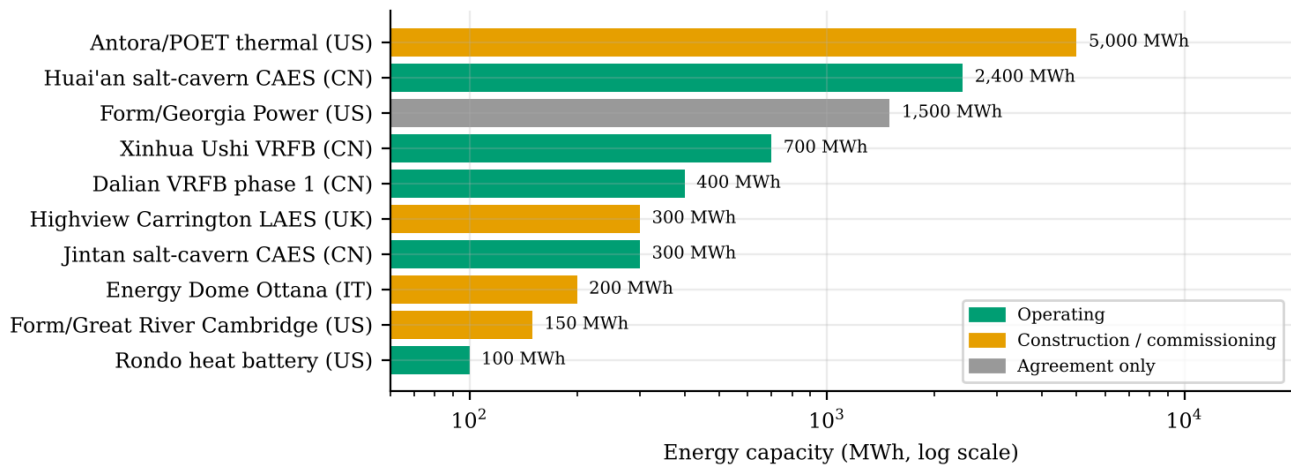


Fig. 4. Selected long-duration storage projects by energy capacity (log scale) and status. Statuses are as reported in [14-20] and may have changed; Antora/POET is a reported 50 MW/5 GWh multi-day thermal installation [20]; Form/Georgia Power is a 15 MW/1,500 MWh agreement [14].

4. Advanced and long-duration storage technologies

4.1. Mechanical storage

Pumped hydro (PSH) lifts water between two reservoirs. Its stored energy is $E = \rho g h V \eta$, so each GWh at a 300 m head needs about 1.4 million m³ of water (derived here, with 90% turbine efficiency; see Eq. 4). Plants last 50 years or more, give inertia and black-start capability, and deliver round-trip efficiencies typically near 75 to 80%. Siting, permitting and construction time (often 5 to 10 years) are the constraints. In India, the CEA estimates a technical potential of about 176 GW [13], and the 2023 plan calls for 175 GWh of pumped hydro by 2031-32 [9].

Compressed-air energy storage (CAES) stores air at high pressure, typically in a salt cavern. Conventional plants burn gas to reheat the expanding air, but the new generation is adiabatic: the heat of compression is stored (in molten salt or pressurised water) and returned on expansion, so no fuel is burned. China's Jintan salt-cavern plant (60 MW/300 MWh, cavern about 1,000 m underground) is the first of its kind in that country, with a reported round-trip efficiency above 60% [15], and the 2.4 GWh Huai'an plant followed with a stated 71% conversion efficiency and an expected output of 792 GWh per year [15]. The cavern gives very low energy cost, but only where geology allows it.

Liquid-air energy storage (LAES) liquefies air at about -196 °C using off-peak electricity, stores it in insulated tanks and re-evaporates it through a turbine. Highview Power's Carrington plant (50 MW for 6 h, 300 MWh) is financed with GBP 300 million, and four 2.5 GWh plants are in early planning [18]. National Grid's scenarios cited by the developer include 2 GW of LAES by 2035, roughly 20% of the UK long-duration need [18]. **CO₂ batteries** (Energy Dome) use the same thermodynamic idea but cycle CO₂ between a gas dome and liquid storage at ambient temperature, which avoids cryogenics; the developer claims a round-trip efficiency of 75 to 80% [16]. A 20 MW/200 MWh plant at Ottana, Sardinia, with an offtake agreement with ENGIE, was reported as nearing completion in late 2024 [16]. **Gravity storage** (lifted blocks or rail) has had far fewer deployments, and its low energy density limits its role.

4.2. Electrochemical storage

Lithium-ion and sodium-ion. LFP lithium-ion batteries dominate four-hour storage and are the benchmark for cost. Because their energy cost scales directly with duration (every extra hour needs another block of cells), they lose competitiveness beyond several hours (Section 6). Sodium-ion batteries use abundant materials and are entering utility use:

CATL unveiled a field-validated 30 MWh-class sodium-ion system in June 2026, quotes 15,000 cycles and 92% capacity retention below -20 °C, and has signed a 60 GWh contract with HyperStrong and a 5 GWh agreement with Alfen for Europe [21]. China's Datang group has connected a 100 MW/200 MWh sodium-ion project [21]. These are 2 to 4 h products, so sodium-ion extends the cost and safety envelope of short-duration storage rather than serving multi-day needs.

Vanadium redox flow batteries (VRFB) separate power (cell stacks) from energy (electrolyte tanks), so duration is increased by adding electrolyte. They have long calendar life and non-flammable electrolyte, and the electrolyte retains value at end of life. Dalian's 100 MW/400 MWh first phase (commissioned 2022) cost about CNY 1.9 billion (about US\$410 million), which is about US\$1,000/kWh at that early stage [17]; Rongke Power has since completed a 175 MW/700 MWh plant and reports more than 2 GWh of cumulative projects [17]. In India, Delectrik has been selected to supply a 100 MWh VRFB at the Khadva solar park in Gujarat [12]. Vanadium price and electrolyte inventory remain the main cost levers.

Iron-air batteries. Form Energy's iron-air battery stores energy by reversible rusting: on discharge iron is oxidised by oxygen from the air, and on charge the rust is reduced back to iron [14]. It is designed for about 100 h at a target cost the developer puts at less than one tenth of lithium-ion; its first deliveries to Great River Energy (1.5 MW/150 MWh) began in October 2025 and full operation is expected in 2026 to 2027 [14]. Form's factory capacity (about 2 GWh per year) is small against the roughly 80 GWh of agreements it has announced [14]. The round-trip efficiency is lower than lithium-ion, which is accepted in exchange for very low energy cost; independent operating data do not yet exist.

4.3. Thermal storage

Thermal storage keeps energy as heat in bricks, carbon blocks, molten salt or packed beds. For industrial heat, no reconversion to electricity is needed, so efficiency is very high: Rondo Energy's 100 MWh heat battery at an oil-recovery site in California reports a round-trip efficiency above 97% for heat delivery, stores at over 1,000 °C (bricks up to 1,500 °C), and loses less than 1% per day [19]. Antora Energy stores heat in carbon blocks and is reported to be commissioning a 50 MW/5 GWh multi-day installation at a bioprocessing plant in South Dakota [20]. When heat must be converted back to electricity (a power-to-power "Carnot battery"), the conversion step cuts efficiency to about 40 to 50%, and the cost advantage then rests on cheap storage media. Molten-salt and adiabatic CAES were the cheapest options for longer durations in the UK network study [7].

4.4. Hydrogen and chemical storage

Power-to-hydrogen-to-power stores electricity as hydrogen made by electrolysis, held in tanks or salt caverns, and converted back through a fuel cell or turbine. Its great strength is that energy capacity is separated from power capacity at very low incremental cost, so it is the only option that scales to seasonal storage; its weakness is a low round-trip efficiency of about 30 to 40% (see Eq. 3) and high power-side capital cost. A recent review of hydrogen-based LDES stresses that short-duration storage cannot handle seasonal mismatches and that component-level studies must be combined with techno-economic and environmental evaluation [5]. The UK study found hydrogen not cost-effective for the durations it assessed [7], whereas a meta-review of LCOS studies expects hydrogen to give the lowest LCOS for seasonal storage while lithium-ion and pumped hydro dominate other applications [8].

Table 3 Summary of storage technologies (typical commercial or demonstrated values; efficiencies marked * are developer claims).

Technology	Principle	Typical duration	Round-trip efficiency	Status (2026)
Pumped hydro	Water lifted between reservoirs	4 to 24 h (up to days)	About 75 to 80%	Mature; 189 GW [2]
Adiabatic CAES	Air in caverns, heat stored	4 to 24 h	60% (Jintan [15]); 71%* (Huai'an)	First 300 MW units in China [15]
Liquid air	Cryogenic air liquefaction	4 to 24 h	Mid-50s to 60% (typical)	First 300 MWh plant [18]
CO ₂ battery	CO ₂ gas dome and liquid storage	4 to 24 h	75 to 80%* [16]	200 MWh plant reported [16]
Li-ion (LFP) / Na-ion	Intercalation cells	0.25 to 8 h	About 85 to 90% (typical)	Mass market [1,21]
Vanadium flow	Redox couples in tanks	2 to 12 h (more with tank size)	About 65 to 75% (typical)	700 MWh plant [17]
Iron-air	Reversible rusting of iron	Up to 100 h	About 40 to 50% (typical)	First 150 MWh [14]
Thermal (heat)	Bricks, blocks, salts	4 to 100 h	Above 97%* heat-out [19]	100 MWh [19]; 5 GWh reported [20]
Hydrogen	Electrolysis, storage, fuel cell or turbine	24 h to months	About 30 to 40% (typical)	Demonstration; many pilots [5]

Table 4 Evidence level for reported performance figures. "Developer claim" means a figure disclosed by a technology company and not independently verified in the sources used.

Figure	Value	Evidence level
Battery cost reduction since 2010	More than 90%	Agency (IEA) [1,22]
Pumped hydro global capacity	189 GW	Industry body (IHA) [2]
Jintan CAES round-trip efficiency	Above 60%	Operator statement [15]
Huai'an CAES conversion efficiency	71%	Equipment supplier claim [15]
CO ₂ battery round-trip efficiency	75 to 80%	Developer claim [16]
Heat battery round-trip efficiency	Above 97% (heat out)	Developer claim [19]

Figure	Value	Evidence level
Iron-air cost vs lithium-ion	Below one tenth (target)	Developer claim [14]
Sodium-ion cycle life	15,000 cycles	Manufacturer claim [21]
Dalian VRFB phase-1 cost	About US\$1,000/kWh	Derived from published investment [17]

5. Applications and value streams

Storage earns revenue from several services whose value depends on duration. **Frequency and ancillary services** need fast response and little energy, which suits short-duration batteries. **Daily energy shifting** (moving midday solar to the evening) is now the main use for lithium-ion, accounting for more than 90% of new projects in 2025 [22]. **Multi-day firming** covers wind lulls and cloudy periods and is where capacity value is increasingly needed: Lazard reports that firming costs rise with intermittent share and names long-duration storage, pumped hydro, geothermal, small modular reactors and carbon capture among the complements [3]. **Seasonal storage** moves summer surplus to winter. **Industrial heat** is a distinct market in which thermal batteries compete with gas boilers and need no electricity reconversion [19]. **Inertia and black-start** are supplied by synchronous machines such as pumped hydro and CAES, which matters as coal plants retire; the Australian study identifies inertia as a key LDES benefit [6]. Fig. 5 and Table 5 give the author's qualitative match between technologies and services.

Li-ion / Na-ion	H	H	L	-	-	L
Flow battery	M	H	M	-	-	L
Pumped hydro	M	H	H	L	-	H
A-CAES	L	H	H	L	-	H
LAES / CO2	L	H	H	L	-	H
Thermal	-	M	H	L	H	L
Iron-air	-	M	H	L	-	-
Hydrogen	-	L	M	H	L	M
	Frequency / ancillary	Daily shifting	Multi-day firming	Seasonal	Industrial heat	Inertia / black start

Fig. 5. Qualitative suitability of technologies for applications (H = high, M = medium, L = low, - = not suited); author's synthesis of [3-8,16-21].

Table 5 Value streams of long-duration storage and what they require.

Application	Key requirement	Typical duration	Best-matched technologies
Frequency, ancillary	Fast response, high cycling	Under 1 h	Li-ion, Na-ion, flow
Daily energy shifting	Low power and energy cost, high efficiency	2 to 8 h	Li-ion, PSH, CAES
Multi-day firming	Very low energy cost, long life	24 to 150 h	Iron-air, A-CAES, thermal, PSH
Seasonal shifting	Lowest energy cost, huge capacity	Weeks to months	Hydrogen, caverns
Industrial heat	Delivered heat at 200 to 1,500 °C	4 to 100 h	Thermal batteries
Inertia, black start	Synchronous or grid-forming capability	Short	PSH, CAES, grid-forming BESS

6. Techno-economic assessment

6.1. Method and assumptions

The levelised cost of storage (LCOS) is the discounted cost of building and operating a storage system divided by the energy it delivers. For a system of power P and duration D , expressed per kW of power capacity and per year, the model used here is

$$LCOS = [CRF \cdot (C_P + C_E D) + F] / (n D) \cdot 1000 + c_{ch} / \eta \quad (1)$$

where C_P is the power-related capital cost (US\$/kW), C_E the energy-related capital cost (US\$/kWh), F the fixed O&M (US\$/kW-yr), n the number of full discharge cycles per year, c_{ch} the charging electricity price (US\$/MWh) and η the round-trip efficiency. The capital recovery factor is

$$CRF = r(1+r)^N / [(1+r)^N - 1] \quad (2)$$

with discount rate $r = 8\%$ and project life N . To compare technologies of different duration on a common basis, the annual discharge is held at $H = n D = 1,500$ full-power hours per year (n is capped at 365 per year), representing a plant that runs in about one in six hours. A charging price of US\$30/MWh is assumed. Table 6 lists the inputs. They are **the author's**

illustrative assumptions, chosen within ranges reported in the literature for mature or targeted costs, and are not taken from any one source; iron-air figures are developer targets [14] rather than observed costs, and no degradation or augmentation cost is modelled. The model is therefore a tool for comparing how costs scale with duration and utilisation, not a project-level price quote.

Table 6 LCOS model inputs (author's illustrative assumptions; $r = 8\%$, charging price US\$30/MWh).

Technology	C_P (US\$/kW)	C_E (US\$/kWh)	Round-trip eff.	Life (yr)	CRF	F (US\$/kW-yr)
Li-ion (LFP)	100	180	85%	15	0.117	8
Vanadium flow	600	250	70%	20	0.102	10
Iron-air (target)	300	25	45%	20	0.102	10
Adiabatic CAES	900	25	65%	35	0.086	15
Liquid air (LAES)	1200	40	55%	30	0.089	15
Pumped hydro	1200	60	78%	50	0.082	15
Thermal (P2P)	1100	30	45%	30	0.089	15
Hydrogen (P2G2P)	2500	3	35%	25	0.094	40

6.2. Results

Table 7 LCOS results at 1,500 discharge hours per year (US\$/MWh). Lowest value in each column in bold.

Technology	4 h	10 h	24 h	100 h
Li-ion (LFP)	106	189	385	1450
Vanadium flow	161	260	498	1788
Iron-air (target)	101	111	134	263
Adiabatic CAES	115	122	142	251
Liquid air (LAES)	148	159	192	372
Pumped hydro	129	147	192	441
Thermal (P2P)	151	160	184	319
Hydrogen (P2G2P)	274	270	273	287

Fig. 6 and Table 7 show the core result. Short-duration cost is dominated by the power term, and at 4 h all non-hydrogen options fall between about US\$101 and US\$161/MWh, at the lower end of, and partly below, Lazard's published range for 4 h US batteries (US\$115 to 254/MWh [3]), as expected for a stylised model without project overheads. Beyond that point lithium-ion's cost rises almost in proportion to duration, because every extra hour needs more cells: it reaches US\$189/MWh at 10 h, US\$385/MWh at 24 h and US\$1450/MWh at 100 h. Under the stated assumptions, other technologies become cheaper than lithium-ion at about the following durations: iron-air 3 h, adiabatic CAES 4.7 h, pumped hydro 6 h and hydrogen 16 h. At 100 h, the cheapest options (adiabatic CAES at US\$251, iron-air at US\$263 and hydrogen at US\$287/MWh) are within about 15% of each other, so the ranking is sensitive to assumptions. Hydrogen becomes cheapest only beyond about 130 h. Two cautions apply. First, the very low iron-air value at short duration comes from its target energy cost of US\$25/kWh and is a statement about the target, not a measurement. Second, vanadium flow looks expensive here because the model uses a mature cost (US\$250/kWh electrolyte-side) that is still well below the first-phase Dalian project of about US\$1,000/kWh all-in [17].

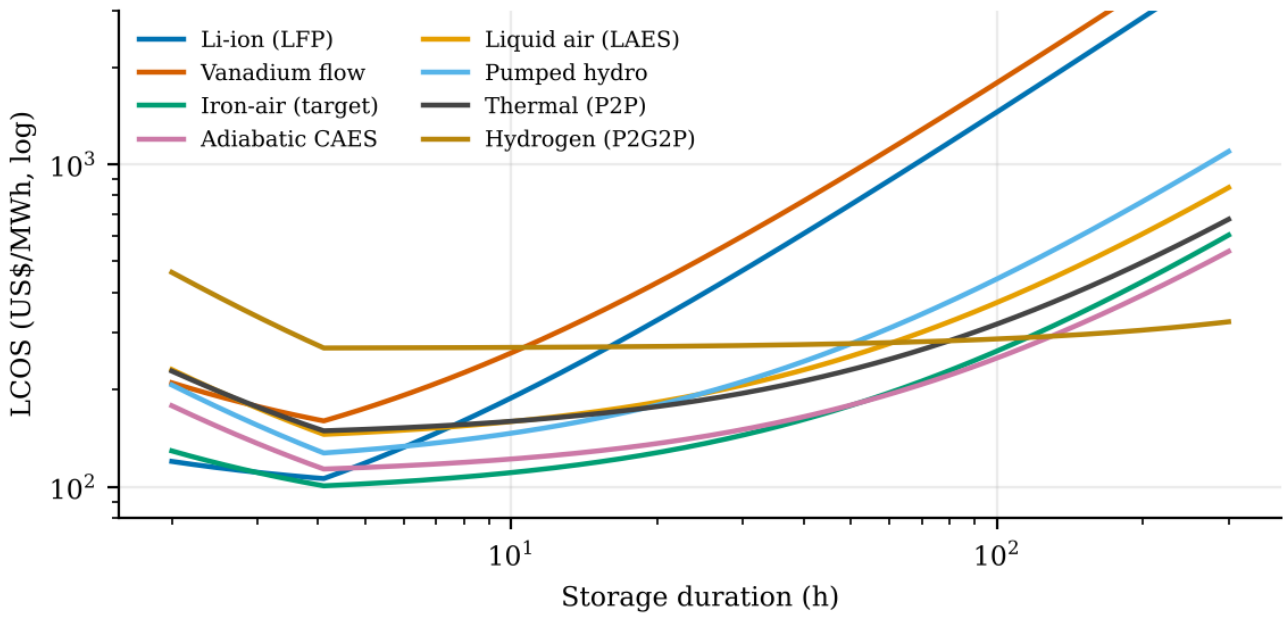


Fig. 6. LCOS versus storage duration for eight technologies at 1,500 full-power discharge hours per year (author's model, Eq. 1; assumptions in Table 6).

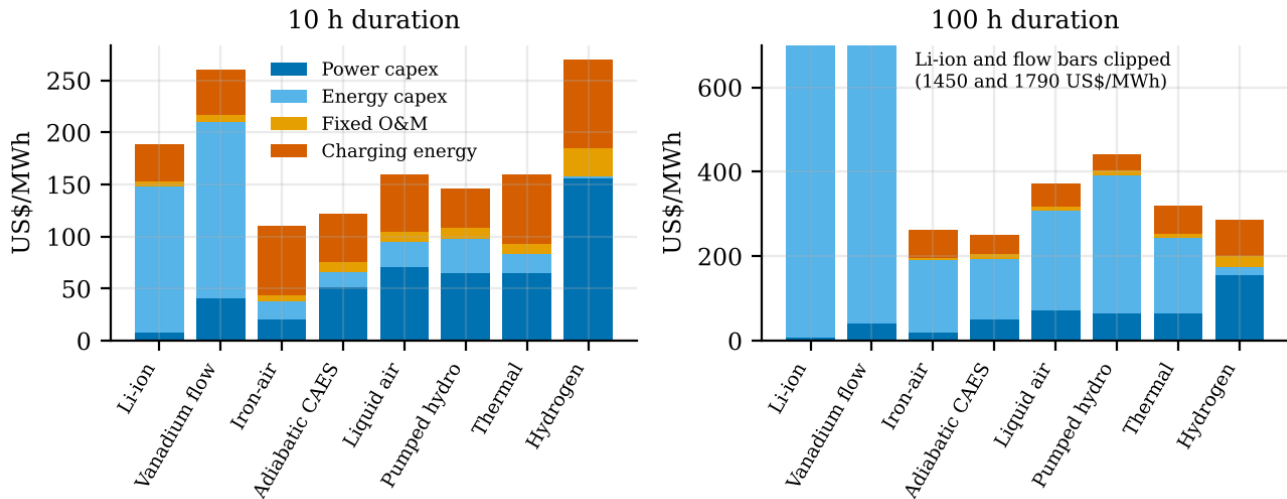


Fig. 7. Breakdown of LCOS at 10 h and 100 h duration. Power capex dominates hydrogen, while energy capex dominates lithium-ion, flow and pumped hydro at long duration (author's model).

Utilisation matters as much as technology (Fig. 8). With 500 discharge hours a year, a 100 h plant costs US\$660/MWh (adiabatic CAES) and with 6,000 hours US\$97/MWh; LCOS roughly falls in inverse proportion to hours because capital is spread over more energy. Low-utilisation technologies with very low energy cost per kWh (iron-air, caverns, hydrogen) therefore suit rare, long events, whereas pumped hydro and thermal do better when the plant cycles often. This is why capacity payments or availability contracts, rather than energy arbitrage alone, are the natural revenue model for multi-day storage; India's pumped-hydro agreements already follow this model, with 40-year fixed capacity charges of about Rs 76 to 77 lakh per MW per year [11].

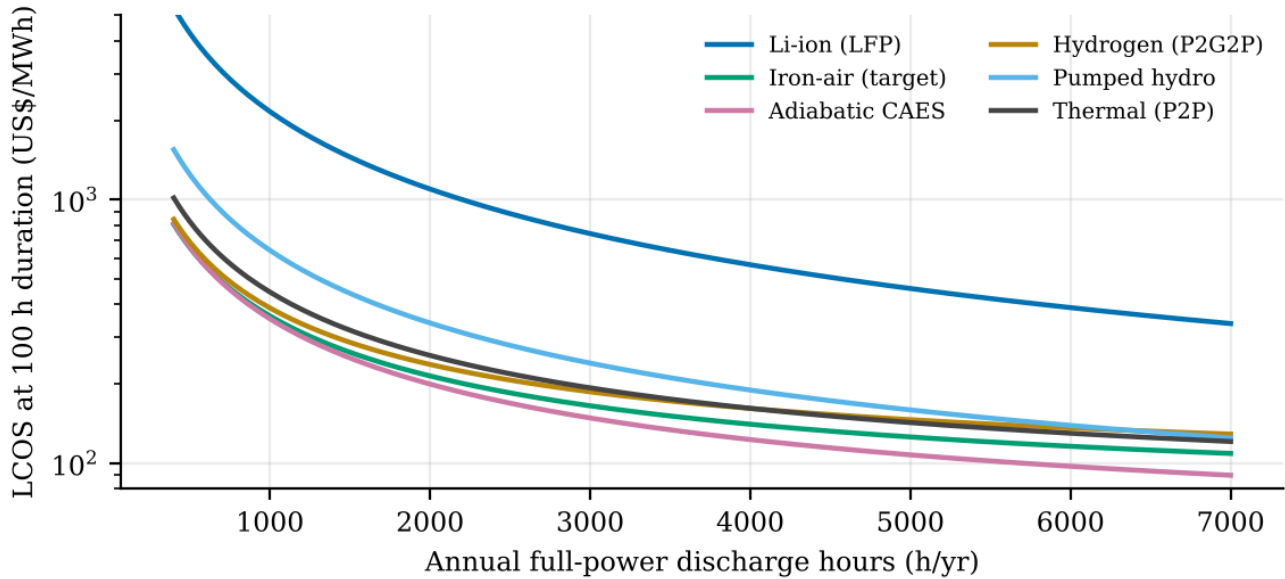


Fig. 8. LCOS at 100 h duration as a function of annual full-power discharge hours (author's model).

6.3. Sensitivity analysis

Fig. 9 varies each input of a 24 h adiabatic CAES plant by $\pm 25\%$ around a base LCOS of US\$104/MWh (at 2,500 discharge hours per year). The largest swings come from utilisation (US\$92 to 123/MWh) and round-trip efficiency (US\$94 to 119/MWh), followed by charging price and discount rate. Capital cost items matter less than often assumed: a 25% change in the energy-related capital cost moves LCOS by only about US\$5/MWh, because for this technology the cavern is cheap. This pattern differs from lithium-ion, where energy capex dominates, and agrees with the finding of a project-level study that increasing efficiency lowers LCOS most when it is below 80%, while technical availability has little influence [8].

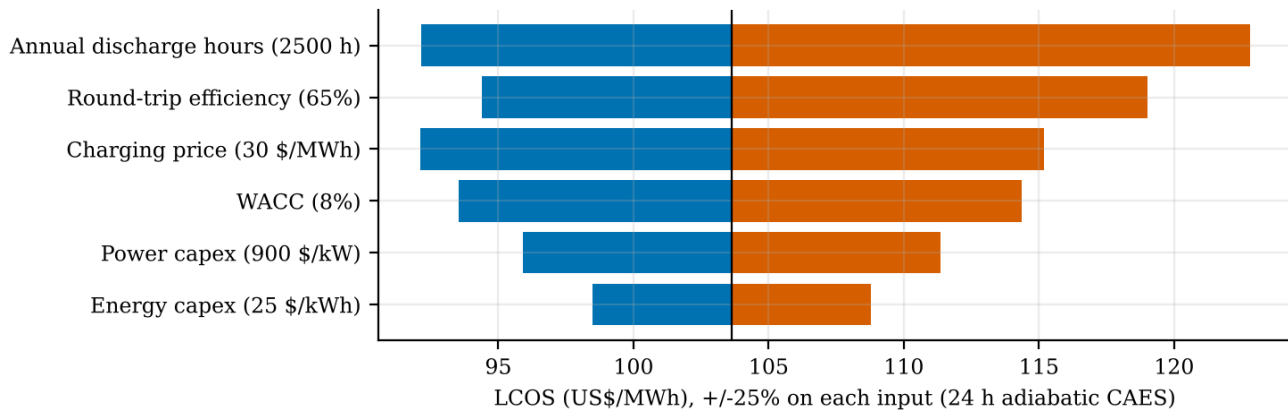


Fig. 9. Sensitivity of the LCOS of 24 h adiabatic CAES to $\pm 25\%$ changes in each input (author's model; base US\$104/MWh).

6.4. Comparison with published studies

Published studies disagree in detail but agree on the pattern. Lazard's 2025 LCOS for US utility-scale batteries is US\$129 to 277/MWh at 2 h and US\$115 to 254/MWh at 4 h, a notable decline that offsets the 2021 to 2024 increases [3]. A review of LCOS studies finds high heterogeneity but concludes that lithium-ion and pumped hydro are generally the most cost-effective across most stationary uses, with hydrogen lowest for seasonal storage [8]. The UK network study ranks molten salt and adiabatic CAES as most cost-effective at long duration and finds hydrogen uncompetitive [7]. The material-level survey finds thermal, chemical and low-cost-material batteries promising for multi-day use, and finds lithium-ion and pumped hydro unpromising for LDES [4]. The present model agrees with all four on direction: lithium-ion wins short, caverns, thermal and iron-air win multi-day, and hydrogen wins only at seasonal duration. It does not replace project-level studies, which carry site, financing and tax details.

7. System value: a dispatch case study

Cost per MWh does not show how much duration a grid needs. To test this, a 14-day synthetic scenario was simulated hourly (author's simulation, not measured data). Demand is flat at 100 MW. Supply is 220 MW of solar with day-to-day cloudiness plus 180 MW of wind modelled as a correlated random process with a mean capacity factor of 35%. A four-day wind lull (days 5 to 9) cuts wind output to 12% of normal. Mean renewable output over the period is 100 MW, equal to demand, so energy is sufficient on average and the problem is purely one of timing. During the lull mean renewable output is only 55

MW. Storage of 100 MW power rating and 80% round-trip efficiency starts half full, charges only from surplus, and discharges to meet shortfalls; surplus beyond storage is curtailed.

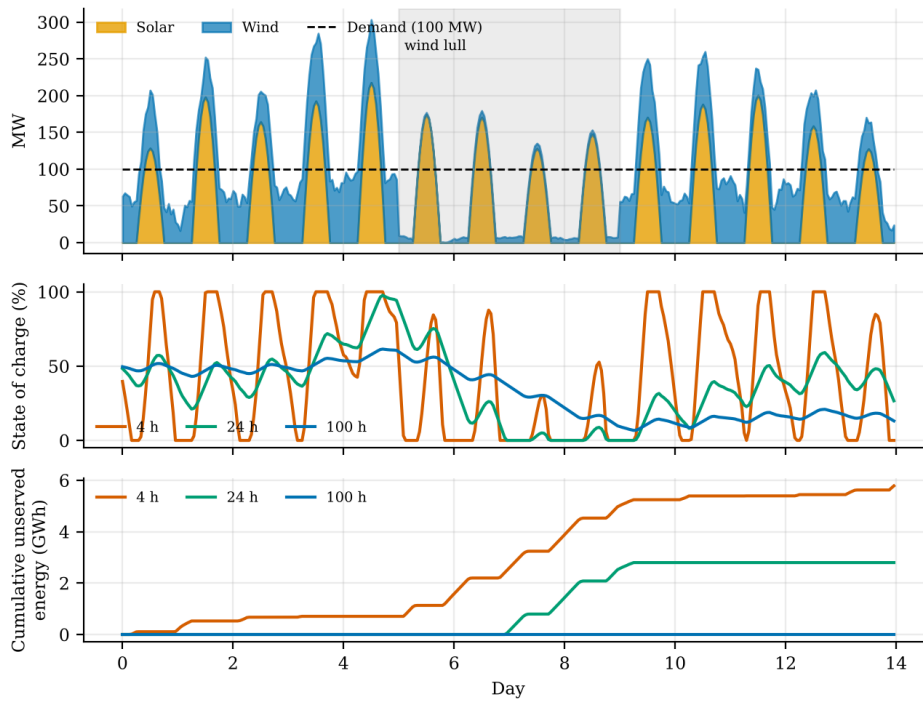


Fig. 10. Dispatch simulation: (top) solar and wind supply against 100 MW demand with a four-day wind lull; (middle) state of charge for 4 h, 24 h and 100 h storage; (bottom) cumulative unserved energy (author's simulation).

Without storage, 69.5% of demand is met. Adding 4 h storage raises this to 82.8%, a gain of 13.3 percentage points, and 24 h reaches 91.7%. Fig. 10 shows why the gain slows: four-hour storage empties during the first night of the lull and never recovers (cumulative unserved energy of about 5.8 GWh), 24 h storage lasts about two days into the lull (about 2.8 GWh unserved), and only 100 h storage rides through it (Table 8, Fig. 11). The marginal value of duration is therefore front-loaded but long-tailed: the first 4 h adds 13.3 points, the next 20 h adds 8.9 points, and the next 76 h adds 8.3 points. In cost terms, the last rung of reliability needs storage whose energy cost per kWh is very low, which is exactly where the technologies of Section 4 differ from lithium-ion. This single scenario cannot give a design rule, since its lull length and renewable mix were chosen by the author, but it illustrates the mechanism that the planning literature describes as falling effective capacity of short storage as renewable share grows [3].

Table 8 Dispatch simulation results: share of 14-day demand served (100 MW power rating, 80% round-trip efficiency).

Storage duration (h)	0	2	4	8	12	24	48	72	100
Demand served (%)	69.5	77.0	82.8	86.8	88.4	91.7	94.9	98.1	100.0

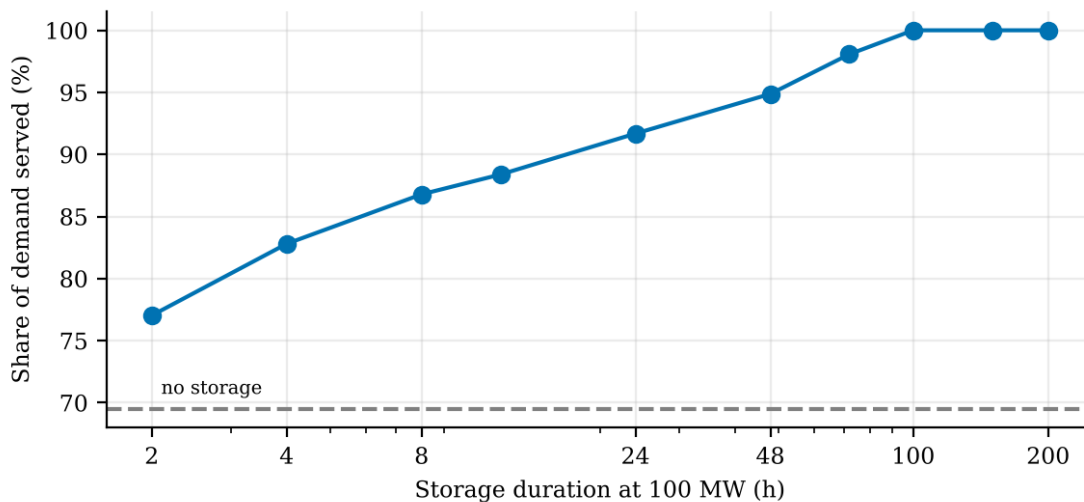


Fig. 11. Share of demand served as a function of storage duration in the simulated wind-lull scenario (author's simulation).

8. Chemical engineering perspective: electrochemistry, thermodynamics and materials

For a chemical engineer, LDES is a materials-and-process problem. The central design question is how to obtain the lowest cost per unit of stored energy, which usually means storing energy in an abundant, cheap medium and making the conversion hardware as small as possible. Three relations explain the technologies of Section 4. First, the round-trip efficiency is the product of the conversion steps:

$$\eta_{RT} = \eta_{\text{charge}} \cdot \eta_{\text{storage}} \cdot \eta_{\text{discharge}} \quad (3)$$

For hydrogen, an electrolyser efficiency of about 65 to 70% and a fuel-cell or turbine efficiency of about 50 to 55% (typical literature values, used here as the author's assumption) give η_{RT} of about 33 to 39%, whereas pumped hydro achieves about 75 to 80% with only mechanical losses. Second, the energy density of the medium sets the physical footprint. For pumped hydro,

$$E = \rho g h V \eta_t \quad (4)$$

so one GWh at a 300 m head with $\eta_t = 0.9$ needs 1.36 million m^3 of water (derived by the author). For sensible thermal storage,

$$E = m c_p \Delta T \quad (5)$$

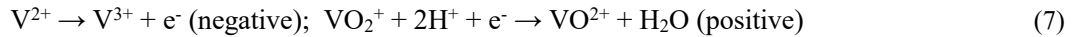
a medium with c_p of about 1 kJ/(kg K) heated by 1,000 K stores about 0.28 kWh per kg, so 1 GWh of heat needs about 3,600 t of storage mass (derived), which explains why thermal stores use cheap bricks, carbon or rock. For compressed air, the isothermal work of compression of n mol is

$$W_{\text{iso}} = n R T \ln (p_2 / p_1) \quad (6)$$

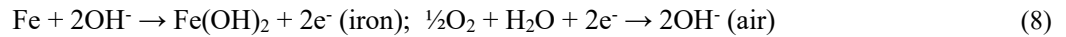
and real compression is closer to adiabatic, so much of the work appears as heat. If that heat is rejected, efficiency falls (hence the fuel needed in conventional CAES); if it is stored in molten salt or pressurised water, as at Huai'an, it is returned on expansion [15]. The same heat-recovery logic applies to liquid air and CO_2 batteries [16,18].

8.1. Electrochemical reactions

In the vanadium flow battery, the negative electrolyte cycles between V^{2+} and V^{3+} and the positive electrolyte between VO^{2+} and VO_2^+ . On discharge:



giving a cell voltage of about 1.26 V. Because energy is held in the dissolved vanadium, duration depends on tank volume and vanadium concentration, and the main materials challenges are membrane cost and selectivity, vanadium price and electrolyte stability. In the iron-air battery, discharge in alkaline electrolyte is



with a theoretical cell voltage of about 1.28 V. The iron and electrolyte cost little, but the air electrode, hydrogen evolution on iron during charge and the resulting efficiency loss are the engineering problems; these are the reasons the round-trip efficiency is much lower than that of lithium-ion [14]. Water electrolysis for hydrogen is



with a reversible voltage of 1.23 V, a thermoneutral voltage of 1.48 V, and practical cell voltages well above these, which is where the efficiency loss arises. Sodium-ion cells follow the same intercalation principle as lithium-ion but with sodium hosts; sodium iron pyrophosphate is reported to be emerging as the most common cathode in storage applications, though CATL has not disclosed its chemistry [21].

8.2. Materials, safety and end of life

Material choice sets both cost and supply risk. The media survey of Aspitarte and Woodside takes the energy capital cost of the storage medium, calculated from commodity prices and physical properties, as the key figure of merit for LDES and finds that low-cost thermal, chemical and battery media can meet multi-day cost targets, while lithium-ion cannot [4]. Safety is another differentiator: Rondo's heat battery uses brick and wire that cannot burn, explode or leak [19], and flow and iron-air batteries use water-based, non-flammable electrolytes [14,17]. At end of life, vanadium electrolyte retains value and can be reused, thermal media are largely inert, while lithium-ion and sodium-ion packs need recycling and, for second life, the sorting problems discussed in the EV literature. Process design for low-emission recycling and electrolyte recovery is an area where chemical engineers can contribute directly.

9. Policy, markets and the Indian context

Policy treatment differs widely (Table 9). In general, markets that pay only for energy arbitrage reward short-duration storage, while capacity or availability contracts are needed to finance multi-day assets whose revenue arrives only a few hundred hours a year (Section 6).

Table 9 Policy and market signals for storage in selected regions.

Region	Key signals	Observed effect / status
India	Viability gap funding for 4 GWh of standalone BESS (about 40% of capex) [23]; ISTS charge waivers extended to 2028 for PSH and solar-plus-battery; state mandates (Rajasthan: RE above 5 MW must include storage) [10]; 40-year PSH capacity-charge PPAs [11]	224 GWh tendered by end-2025; 0.7 GWh BESS operating [10]
China	Pumped-hydro target of 120 GW by 2030 [2]; 2025 reform removed broad renewable co-location mandates [22]	63 GW of battery additions in 2025 [22]; large CAES and flow plants [15,17]
Europe	52.9 GW pumped-hydro pipeline [2]; national schemes	Battery additions of about 6.2 GW in 2025 [22]
United States	Federal investment tax credits (treated in Lazard's analysis) [3]; DOE initiative to cut LDES cost 90% in a decade [24]	About 19 GW of batteries in 2025 [22]; first iron-air deployments [14]
UK	Network studies and developer programmes for LDES [7,18]	First 300 MWh liquid-air plant under construction [18]
Australia	State and federal procurement; coal retirement	Nearly 8 GW of batteries in 2025 [22]; batteries 18% of dispatchable capacity

9.1. India

India's storage requirement is large, and the gap between plan and operation is wide. The CEA's National Electricity Plan estimates a need for 74 GW/411.4 GWh of storage by 2031-32, made up of about 47.24 GW/236.22 GWh of batteries and 26.69 GW/175.18 GWh of pumped hydro, and 320 GW/2,380 GWh by 2047, of which 230 GW/1,840 GWh would be batteries and 90 GW/540 GWh pumped hydro [9]. These imply storage durations of about 5.0 h (batteries) and 6.6 h (pumped hydro) in 2031-32, and about 8.0 h and 6.0 h in 2047 (derived here), so the CEA plan itself anticipates a gradual lengthening of duration. India's pumped-hydro potential is about 176 GW [13].

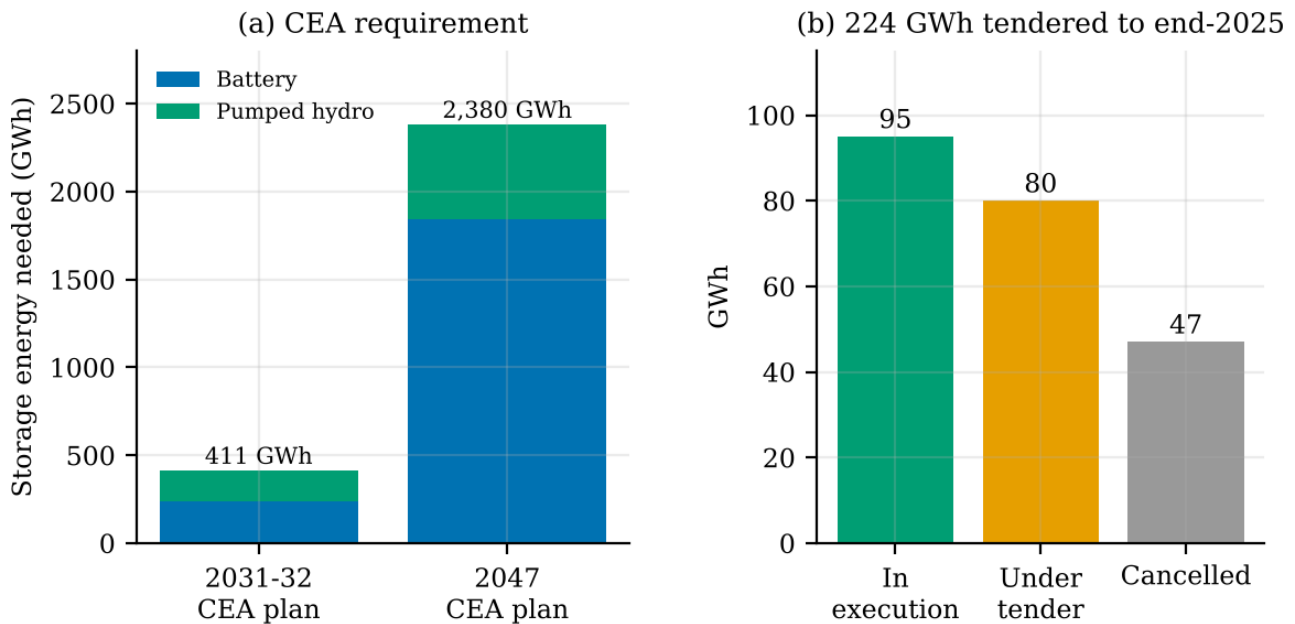


Fig. 12. India: (a) CEA storage requirement in GWh, split by technology [9]; (b) status of the 224 GWh of storage tendered to end-2025 (92 GWh battery, 132 GWh pumped hydro) [10].

Against these numbers, only 0.7 GWh of battery storage was operating in 2025, with 2 GWh more expected by December 2026 [10]. In other words, the 2031-32 battery requirement is about 340 times the 2025 operating base (derived). On the tender side, activity is high: 224 GWh had been tendered by 31 December 2025 (92 GWh battery, 132 GWh pumped hydro), of which 95 GWh was in execution, 80 GWh still under tender and 47 GWh cancelled, and 2025 alone saw 69 tenders totalling 102 GWh [10]. Cancellations show the risk of aggressive bidding. Pumped hydro is leading the long-duration segment: Uttar Pradesh signed PPAs for 2.75 GW/22 GWh (8 h) in April 2025 [11], an SECI tender for pumped hydro was revised upward to 1,500 MW/12,000 MWh and contracts for 1,344 MW were reported awarded [12], and about 44.5 GW of pumped hydro is in development nationwide (early 2025) [2]. Non-lithium long-duration options are also being tried: Delectrik's 100 MWh vanadium flow battery at the Khadva solar park in Gujarat and NTPC's trial of the Energy Dome CO₂ battery [12]. For a country with a 500 GW non-fossil target for 2030 [10], the practical priorities are to convert tenders to operating plants, to adopt capacity-based contracts for long-duration storage, and to test non-lithium technologies in Indian conditions, including high ambient temperature that affects thermal management of batteries.

10. Discussion: maturity and cross-layer interactions

Technologies are at very different maturity (Fig. 13). Pumped hydro and four-hour lithium-ion are fully commercial. Flow batteries, thermal batteries and adiabatic CAES are at first commercial scale, mostly in China or in single-site projects. Iron-

air, liquid air, CO₂ batteries and hydrogen reconversion are at first-of-a-kind or pilot scale, and thermochemical and gravity systems are earlier still. Planning for the next five years should therefore rely on pumped hydro and lithium-ion for firm commitments while funding demonstrations of the immature options, and procurement should require independent performance data rather than claims.

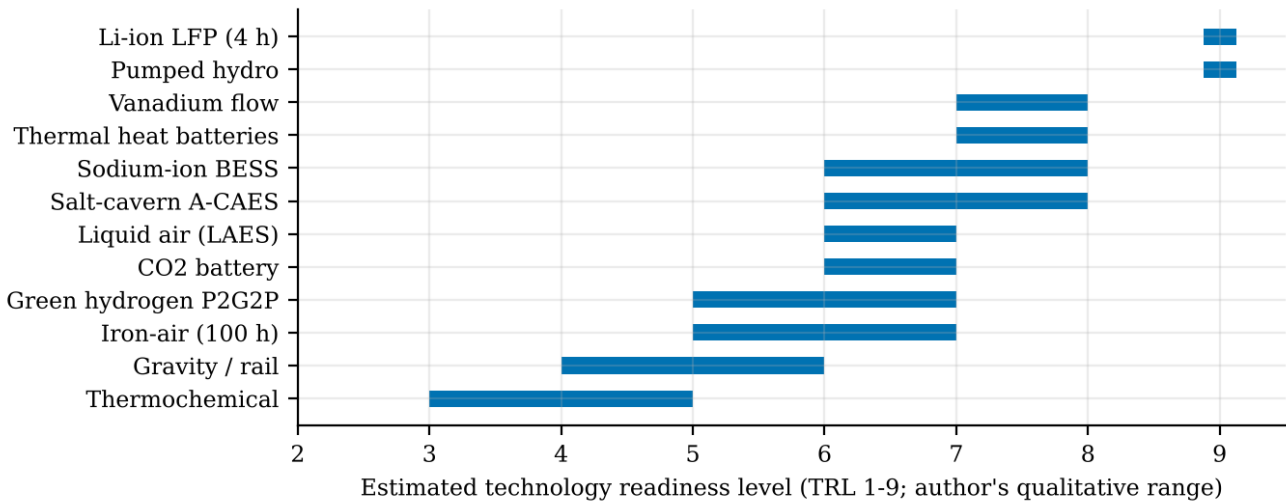


Fig. 13. Estimated technology readiness of selected storage technologies (author's qualitative assessment based on [2-8,14-21]; ranges indicate variation between projects and markets).

Table 10 Cross-layer interactions and design implications (author's synthesis).

Interaction	Evidence	Implication
Duration and cost structure	Li-ion LCOS scales with hours; cavern and tank media do not (Fig. 6, Fig. 7) [4]	Choose technology by duration class, not by a single benchmark
Utilisation and revenue	LCOS roughly inversely proportional to discharge hours (Fig. 8)	Capacity or availability contracts for multi-day assets [11]
Renewable share and storage value	Effective capacity of 4 h storage falls as solar rises [3]; dispatch test (Fig. 10)	Plan duration together with renewable build-out
Efficiency and energy cost	Low-efficiency, low-cost media can still win at long duration (iron-air, hydrogen)	Judge on LCOS and sensitivity, not efficiency alone
Evidence and finance	Many figures are developer claims (Table 4)	Independent testing and staged procurement
Siting and policy	PSH and caverns are geology-bound; permitting is slow [2,13]	Early resource mapping and streamlined approvals

11. Challenges and research gaps

Table 11 Challenges, gaps and research directions.

Area	Challenge	Direction
Cost evidence	Few independent costs; reliance on developer claims	Open cost databases, bankable demonstration data
Pumped hydro	Siting, permitting, long build time	Closed-loop and retrofit designs, faster approvals
Mechanical (CAES, LAES)	Geology, first-of-a-kind engineering, efficiency	Heat recovery, artificial caverns, long-term operating data
Flow and iron-air	Vanadium cost, membranes, air-electrode losses	Cheaper electrolytes, iron-air efficiency improvement, scale-up
Thermal	Reconversion efficiency, high-temperature materials	Better turbines, cheaper media, industrial heat integration
Hydrogen	Low round-trip efficiency, electrolyser capex	Cheaper electrolyzers, cavern storage, system-level optimisation
Markets and finance	Revenue model for rare, long events	Capacity contracts, reliability products, cost of firming accounting
India	0.7 GWh operating versus 411 GWh planned; cancelled tenders [10]	Execution capacity, domestic manufacturing, field trials of non-lithium LDES

Further gaps include the lack of long-term degradation data for flow, iron-air and sodium-ion systems; the absence of standard methods to compare LCOS between studies, which a meta-review flags as a source of heterogeneity [8]; limited life-cycle assessment of new storage chemistries; and the need for system models that value duration directly instead of using fixed capacity credits.

12. Future trends

Several trends are likely to shape the next decade. (i) **Longer batteries.** Average project duration is already rising [22], and cheaper cells (including sodium-ion at GWh scale [21]) will extend that to 6 to 8 h, putting pressure on the 8 to 24 h gap. (ii) **First commercial multi-day plants.** From Energy's first deliveries, Antora's multi-day thermal plant and the first liquid-

air and CO₂ battery plants will provide the operating data that the industry lacks [14,16,18,20]. (iii) **Scale-up in China.** Gigawatt-hour compressed-air and flow-battery projects are being built there [15,17], and costs from these projects will influence global prices. (iv) **Pumped-hydro revival.** A 600 GW pipeline, led by China, Europe and India, points to more long-duration capacity beyond 2030 [2]. (v) **Industrial heat.** Thermal batteries may reach scale earlier in heat markets than in power markets [19]. (vi) **Digital optimisation.** Digital twins and learning-based dispatch will help co-optimize storage across several markets [5]. For India, the priority lies in pumped hydro and solar-plus-storage at scale, with pilots of two or three non-lithium options.

13. Conclusions

This review combined agency data, peer-reviewed techno-economic work and project disclosures with three original analyses. The main conclusions are as follows.

- Short-duration storage has become mainstream: 108 GW of batteries were added in 2025, but the average project lasts only about three hours, so the next challenge is duration, not capacity [1,22].
- Pumped hydro still supplies the great majority of stored energy (189 GW installed, 600 GW in the pipeline), and new technologies (adiabatic CAES, flow batteries, liquid air, CO₂ batteries, heat batteries, iron-air) have only just reached their first commercial plants [2,14-20].
- In the author's LCOS model, lithium-ion is cheapest up to about 2 to 3 hours, while at 24 h it costs about US\$385/MWh against about US\$142/MWh for adiabatic CAES, and at 100 h the options with low energy-capital cost (CAES, iron-air, hydrogen) are within about 15% of each other; the ranking depends on assumptions, and iron-air values are developer targets.
- Utilisation, round-trip efficiency, charging price and discount rate move LCOS more than capital cost in cavern-based storage, so revenue design (capacity contracts) matters as much as technology.
- In the dispatch simulation, 4 h storage lifts demand served from 70% to 83%, but a four-day wind lull needs about 100 h to be fully ridden through; the marginal value of duration is front-loaded and long-tailed.
- India needs 411 GWh of storage by 2031-32 but had 0.7 GWh of batteries operating in 2025; pumped hydro is leading long-duration procurement, and execution of tenders is now the main risk [9-12].

Future work should validate the technologies with independent operating data, extend the model to include degradation and revenue stacking, and combine system-planning and storage models for Indian conditions.

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Declaration of competing interest

The author declares no known competing financial interests or personal relationships that could have influenced this work.

Data availability

No new experimental data were generated. Market, cost and project figures are taken from the cited sources. The LCOS model, sensitivity analysis and dispatch simulation are the author's calculations; their inputs are given in Table 6 and Section 7, and the simulation uses a fixed random seed so that it can be reproduced.

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