Filling The Policy Gap For Long-Duration Energy Storage:

Strategic Reserves And Market Mechanisms

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Acknowledgements

This briefing paper was written by S-Curve Economics and University College London (UCL) as an input to the UK-China Power Market Reform Advisory Group.

The authors thank the following peer reviewers: Keith Bell (Strathclyde University); Oliver Broad and Francisca Jalil-Vega (UCL); Will Broad and Mahika Krishna (LDES Council); Johanna Bowyer (IEEFA Australia); Hongye Guo and Menghsu Shi (Tsinghua University); Shai Hassid (Ofgem); Alejandro Hernandez, Neil Lessem, Monika Morawiecka and Dominic Scott (Regulatory Assistance Project); Anders Hove (Oxford Institute of Energy Studies); Camille Paillard (International Energy Agency); and Jack Pardoe (Octopus Energy Group).

The contents of this report represent the views of its authors, and should not be taken to represent the views of the UK government, our funders, or the organisations to which the authors are affiliated.

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The UCL Centre for Net Zero Market Design (CNZMD), part of the Bartlett's Institute for Sustainable Resources, provides independent, evidence-based research and analysis to inform policies for a rapidly decarbonising UK energy system. Its work focuses on the market and regulatory reforms needed to sustain the UK electricity sector transition, with particular attention to maintaining investment and improving storage and flexibility to help reduce electricity bills. Building on earlier stakeholder-engaged work and its engagement with the UK government's Review of Electricity Market Arrangements (REMA) and subsequent programmes, the Centre combines independent policy research, international comparison, stakeholder capacity building, and training a new generation of electricity market expertise to support delivery of an investible market that operates efficiently for businesses and consumers.

Contents

Key messages

1. Wind-dominated electricity systems like the UK will need long-duration energy storage (LDES) in addition to short-duration batteries, to meet security of supply and to enable the most productive use of high volumes of low-cost renewable power.

2. As transport, industry and heating are increasingly electrified, electricity's share of final energy demand in the UK economy could rise from 18% now to 70% by 2050.

3. The UK holds strategic oil stocks and is attempting to restore national gas stores. As electricity takes over many of the roles previously provided by oil and gas, the strategic adequacy of electricity supply deserves equivalent attention. LDES is an important part of the solution.

4. Understanding energy storage in terms of **four different duration regimes** – short-duration (0-10 hours), inter-day (10-48 hours), inter-week (48-300 hours) and seasonal (>300 hours) – based on the services and markets addressed and the relevant technologies, helps to identify what type of storage is needed when, how often, and the policies to support its deployment and operation.

5. **Short-duration energy storage (SDES)** is already being deployed rapidly in the UK, benefiting from the ability to stack revenues from the wholesale, balancing, ancillary services and capacity markets. Its rate of deployment is roughly in line with system needs.

6. Countries with policy mechanisms that contribute some predictable and/or stable revenues for SDES (such as Great Britain's Capacity Market), have greater deployment of SDES than those without. The need for policy support for LDES is greater, given its likely greater uncertainty of revenues, and lower levels of technological maturity. Despite this, few countries yet have dedicated LDES policies in place.

7. LDES has long lead-in times. Planning, permitting, construction and connection of LDES can take 5-15 years, meaning that the LDES capacity of the system in the mid-2030s may depend on policy decisions made now.

8. The UK's LDES Revenue Cap-and-Floor Mechanism is a useful initial policy step to support greater deployment of LDES, but it should be reformed to help bring forward the diversity of LDES technologies and duration types needed for the UK's future energy system.

9. The LDES Revenue Cap-and-Floor Mechanism is best suited to **inter-day LDES** (c.10-48 hours). Within a decade, this type of LDES could be used around one hundred times per year, to bridge periods of surplus and deficit output arising primarily from the combinations of wind, solar PV and nuclear generation. Modifying the LDES Revenue Cap-and-Floor Mechanism to include separate auction 'pots' for storage of different minimum durations, a lower minimum TRL requirement, and a smaller minimum project size could support sufficient investment in inter-day LDES in line with system needs.

10. At the other end of the range, **seasonal LDES** will be needed only rarely to ensure security of supply during extreme outlier events of low wind and solar output and high demand over multiple weeks. Market-based policies such as the LDES Cap-and-Floor may not incentivise sufficient deployment of seasonal LDES or ensure it is available when needed. State ownership and operation of seasonal LDES in a strategic reserve is likely to provide greater security of supply at comparable or lower cost than market-based approaches.

11. **Inter-week LDES** is likely to be needed several times a year (our projections suggest around ten times per year in 2030, 2035 and 2040), for relatively low frequency but potentially high impact scarcity events. Given the increasing importance of secure electricity supply in the future economy, centralised dispatch of inter-week LDES assets could be preferable to self-dispatch, to ensure their availability when they are most needed. Further work is needed to assess whether a reformed Revenue Cap-and-Floor would be effective to deploy enough inter-week LDES and operate it in line with system needs, or if including this category of LDES within a strategic reserve would be more beneficial.

Introduction

The UK's electricity system is decarbonising rapidly in tandem with the electrification of its economy. The electricity system is increasingly dominated by weather-dependent renewable power generation, particularly wind. These assets have uncertain supply profiles, resulting in more frequent periods of over- or under-supply relative to electricity demand.

At the same time, security of electricity supply is becoming increasingly important, as transport, heating and industry electrify. Electricity's share of total energy consumption is forecast to rise from around 20% today to between 40-70% by 2050.[1]

Security of supply can be met with a range of technologies: energy storage of different durations, low-carbon dispatchable technologies (such as gas with carbon capture, utilisation and storage (CCUS) and hydrogen to power), demand-side flexibility, interconnectors and unabated thermal power generation. While the latter is, to date, the primary source of energy security in the UK, the UK's use of unabated gas will decline as the country pursues its goals of Clean Power 2030 and 2050 net zero emissions, necessitating a greater role for energy storage and low-carbon fuels.

This briefing paper examines the need for energy storage in the UK, particularly long-duration energy storage (LDES), to (1) increase productive use of potential 'surplus' renewable power and (2) to support security of electricity supply. Four durations of energy storage are considered, each providing different system services: short-duration energy storage (SDES), inter-day medium-LDES, inter-week LDES and seasonal LDES. Given the UK's successful ongoing deployment of short-duration batteries, the briefing paper focuses on the challenges with LDES and possible policy mechanisms to support investment in and operation of LDES of different types. Different procurement strategies and operational rules are needed across LDES duration categories. Considering market participation potential across LDES durations, we suggest that a state-owned strategic energy storage reserve could be appropriate for seasonal LDES, while different market-based policies could be suitable for inter-day and inter-week LDES.

1. Dependent on scenarios. NESO Future Energy Scenarios 'Electric Engagement' implies around 60-70% of final energy consumption from electricity, 'Holistic Transition' implies around 45-60%, 'Hydrogen Evolution' implies around 40-60%. NESO (2025) FES: DESNZ finds the proportion is 'around half' by 2050 – see DESNZ (2020), *Modelling 2050: electricity system analysis*. Note that total final energy demand in 2050 is likely to be much lower than today due efficiency gains from electrical technologies, particularly electric vehicles and heat pumps.

> It is useful to consider a taxonomy that captures storage types in terms of both duration and system need.

A taxonomy for energy storage

Energy storage is a technology-agnostic term, comprising ‘two-way’ assets that can both absorb and supply energy. These assets are typically discussed in terms of energy capacity, power, and associated discharge duration. In UK policy, LDES is defined as storage that can continuously discharge for 8 hours or more. However, these technologies have different use-cases in line with the system services they can provide. These include time-shifting, capacity adequacy and market liquidity, which have implications for generation capacity and network build requirements. Through the lens of system planning and associated policy, it is therefore useful to consider a taxonomy that captures storage types in terms of both duration and system need. This briefing paper uses a taxonomy developed by researchers at University College London, of four different storage duration regimes based on the markets and services each addresses and the relevant technologies (Figure 1).[2]

2. Ragazzi et al. (2026). *Energy storage modelling for evolving power systems.*

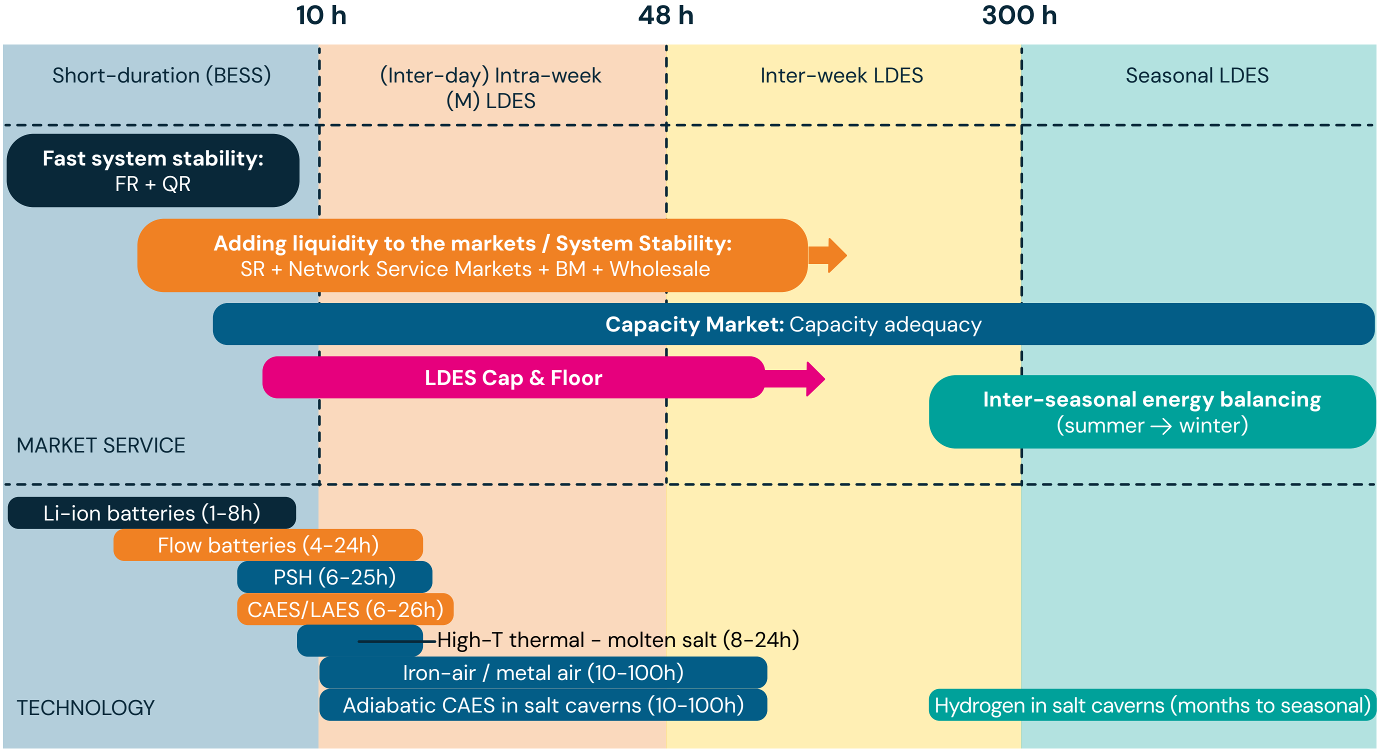
1. **Short-duration battery energy storage systems (BESS) (approximately 1–10 hours):** Provide frequency response and other fast ancillary services, as well as supporting market liquidity through energy arbitrage. These are predominantly lithium-ion batteries at 1–4 hours' duration, with single-cycle configurations extending to around 8 hours. Most operational storage in Great Britain (GB) is in this category, with an average duration of 1–2 hours.

2. **Intra-week, inter-day medium-duration LDES (M-LDES; 10–48 hours):** Shifts energy over several hours to multi-day periods, principally serving to add liquidity to markets that, over periods of several hours, would otherwise depend on a small number of thermal plants. The relevant markets are ramping reserves, the Balancing Mechanism, and wholesale arbitrage. Flow batteries (4–24 h), pumped storage hydro (PSH) (6–25 h), compressed air energy storage (CAES) and liquid air energy storage (LAES) (6–26 h), high-temperature thermal storage in molten salt (8–24 h), and adiabatic CAES in salt caverns (10–100 h) serve this regime.

3. **Inter-week LDES (48–300 hours):** Shifts energy to provide capacity adequacy and system reliability across large-scale weather events such as 'dunkelflaute' periods of low wind and sun, lasting several days to roughly two weeks. Current policies that could in principle provide market signals are the Capacity Market and the LDES Revenue Cap-and-Floor, although neither policy is currently supporting LDES of this duration. PSH, CAES variants, and iron-air or metal-air batteries at approximately 50–100 hours are the relevant technology families.

4. **Seasonal LDES (>300 hours; weeks to months):** Provides inter-seasonal balancing from summer surplus to winter deficit. The market and policy structure here is sparse; no merchant signal in GB extends to seasonal shifting, and the Revenue Cap-and-Floor, with a minimum duration of 8 hours for projects, only partially covers this regime. Hydrogen stored in salt caverns is the technology candidate at this scale; no operational GB capacity exists today.

Figure 1: Energy storage duration taxonomy by predominant system service



Source: *Ragazzi et al. (2026), University College London. The abbreviations of technologies are BESS, battery energy storage systems; PSH, pumped storage hydro; CAES, compressed air energy storage; LAES, liquid air energy storage; High-T, high temperature. The range of technologies represented is not exhaustive but focuses on the options at higher levels of technology readiness.*

Short-duration energy storage

The UK is a relative success story for SDES policy development and capacity deployment. The availability of multiple revenue streams – from the Capacity Market, wholesale electricity market, and ancillary services – has been critical to the financial viability of BESS.[3] The Capacity Market is particularly important as a stable source of revenue, even though its contribution is not as large on average as those of the Balancing Mechanism or wholesale arbitrage, as these can be extremely volatile.[4] As a result of this revenue stacking potential, Great Britain is the largest market for BESS in Europe, with about 7.3 GW or 12 GWh operating.[5]

Market-based procurement strategies have resulted in a pipeline for BESS that is about three times larger than the government's Clean Power 2030 target of 23–27 GW (~46–108 GWh),[6] and many of these are seen as viable projects.[7] However, grid connection delays, network outages that prevent battery testing or energising, and supply chain bottlenecks are lowering projected operational capacity and risk deployment falling short of the 2030 target.[8] These problems exemplify the role of broader system conditions in determining procurement timelines. System-level operational efficiency considerations, for example, introduction of stronger locational signals to relieve grid congestion, are a possible area of policy improvement. While important, these opportunities to improve procurement conditions for SDES are not the focus of this paper.

3. UCL (2025). *Banking on batteries: a dynamic financial appraisal of utility-scale BESS in Europe*.
4. Between 1 August 2025 – 1 July 2026, the Capacity Market has contributed an average of around £7,447/MW/year to the GB BESS revenue stack, out of a total average of around £57,984/MW/year, representing roughly 13% of total revenue. Its share never fell below 8% or exceeded 22%, reflecting the predictable, availability-based nature of CM payments. Its share rises in winter months when total revenues dip (e.g. hitting 22% in February 2026). In contrast, during the same 12 months, revenue share from the Balancing Mechanism and wholesale arbitrage have swung between negative and positive values, -21–64% and -15–68%, respectively, averaging an annual contribution of £13,563/MW/year or 23% of total revenue for the BM and £11,624/MW/year or 20% for wholesale arbitrage. Modo Energy live index, data as of 14 July 2026.
5. Modo Energy live index, data as of 1 May 2026.
6. The range of energy capacity (GWh) equivalent of the Clean Power 2030 battery target assumes that new build batteries will have a duration of between 2- to 4-hours, given 95% of new builds in 2025 had a duration of 2 hours or more, according to Modo Energy. See Modo Energy (2026). *GB BESS buildout Q1 2026*.
7. Adding all 17 GW of storage projects with CM agreements to the existing capacity would take us to around 21–23GW by 2029, with two auctions to spare – DESNZ (2025). Statutory security of supply report: See also Modo Energy (2026).
8. Modo Energy (2026). *GB BESS buildout Q1 2026* (as above).

Long-duration energy storage

Here we first consider the increasing need for long-duration energy storage in general, before illustrating how the need varies across duration categories.

The increasing need for LDES

In contrast to SDES, a significant acceleration in the deployment of LDES is required to ensure security of supply and cost-effective use of renewable power in the context of progress towards the Clean Power 2030 and 2050 net zero goals.

Currently, the UK has ~3 GW (~48 GWh) of operational LDES capacity, of which 2.8 GW is PSH with average 17-hour duration. Additional flexible capacity is provided by ~35 GW of unabated gas. Unabated gas has been the main security of supply resource; as these assets approach end of commercial life, the UK must decide which fuels, technologies, and associated policies to support to maintain system security. The Clean Power 2030 goal is for LDES capacity to grow to 4-6 GW (~40-120 GWh) as part of 40-50 GW of 'dispatchable long-duration flexible capacity', the rest being low-carbon fuels such as gas with CCUS or hydrogen to power (which can also count as a form of replenishable energy storage).[9]

> LDES investment timelines require decisions be made anywhere between 5-15 years ahead of operational need. LDES capacity of the mid-2030s therefore depends on policy decisions made now.

Build times for LDES technologies range from ~2 years for BESS (flow or large lithium-ion) to 5-10 years or more for PSH, with most scalable technologies falling in the 3–6-year range. On top of construction, planning, permitting, and grid connection delays can add 2-5 years to delivery timelines.

Looking to 2050, estimates of UK LDES capacity need vary significantly. The Royal Society estimates up to 100 TWh of LDES is needed to complement power generation from solar, wind and nuclear in a 2050 net zero scenario.[10] The estimates within the NESO Future Energy Scenarios are an order of magnitude lower,[11] but still imply up to three times more LDES capacity than the government's 2030 target will be needed by 2050.[12] Estimations vary given uncertainty regarding future energy mix, demand, weather conditions and system reliability standards.[13] However, all analyses call for LDES deployment on a substantial scale, with the general consensus among experts being that tens of terawatt hours will be needed to decarbonise the grid.[14]

Weather uncertainty is particularly challenging given the wind-dominant, high-VRE electricity system the UK is building. As the electricity system becomes more weather dependent, the supply profile becomes more volatile.

This creates a need to shift energy 1) to the time of day it is needed (a service well suited to SDES) and 2) across days or weeks, by absorbing greater volumes of surplus during high-generation events and contributing to security of supply during sustained low-generation weather events. These critical services require storage of longer durations. This correlation between VRE penetration and LDES requirement is represented in Figure 2.

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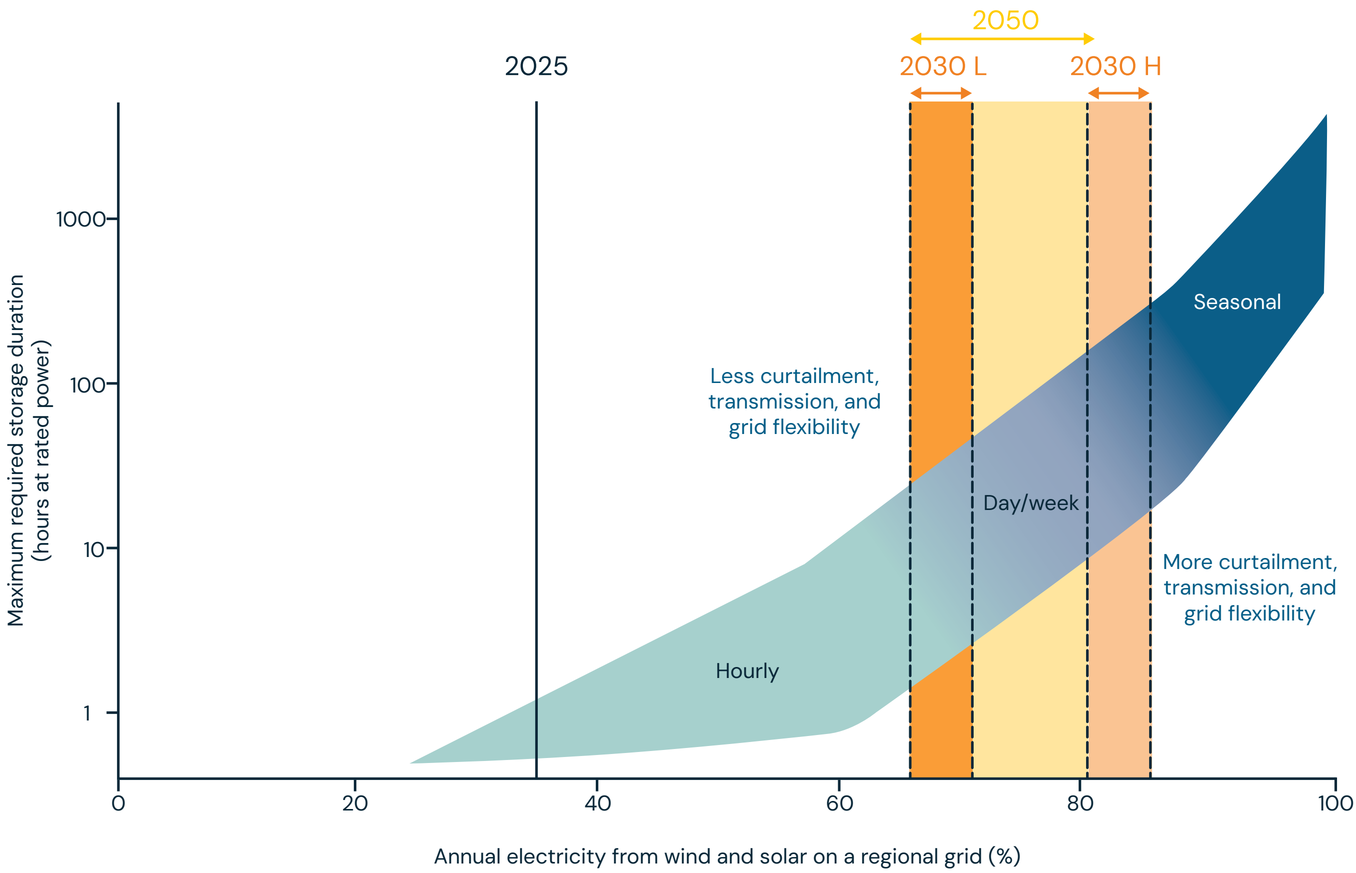
9. DESNZ (2025). *Clean Power 2030 Action Plan*. A note on terminology: in this briefing, 'LDES' refers to long-duration energy storage which encompasses long-duration electricity storage and hydrogen to power, which DESNZ classifies as long-duration flexible capacity. The CP2030 Action Plan distinguishes these two categories of dispatchable resource.
10. Royal Society (2023). *Large-scale electricity storage*. The LDES technology recommended is hydrogen stored in salt caverns as it has the lowest cost per unit of energy stored. The authors identify that having a mix of hydrogen and advanced compressed air energy storage could be more cost-effective, due to the low storage cost of the former and the efficiency of the latter and recommend this for further investigation.
11. The NESO FES 'Holistic Transition' pathway estimates 3.334 TWh of LDES is needed in 2050: 3,310 GWh hydrogen, 120 GWh pumped hydro, 58 GWh batteries, 22 GWh liquid air and 4 GWh compressed air energy storage. This level of LDES implies virtually no change in capacity from the CP2030 target, although the technology mix changes. NESO (2025) FES, Figure 17.
12. To enable comparison with the 40-50 GW LDES target in CP2030, assumptions have been made about the discharge duration of the 100 TWh of (mainly hydrogen) storage estimated by the Royal Society. For the Royal Society estimate, using the authors' data on hydrogen capacity in Table 8 of the report, it is inferred that hydrogen storage can continuously sustain 1GW of output for 636 hours, approximately one month. At one month's duration, the 100TWh of LDES capacity estimated could therefore provide around 150GW of firm power.
13. Existing analyses of LDES need have shortcomings, such as not accounting for the role of short-duration storage, interconnection and other flexible resources that could impact LDES need; not all stress-test estimations using long-run weather datasets (historic and future climate projections) to capture rare weather events; and there are few UK-specific studies. Further analysis is required to test the sensitivity of estimates of LDES need under different scenarios and assumptions.
14. House of Lords Science and Technology Committee (2024), *Long-duration energy storage: get on with it*.

Figure 2: Semi-quantitative overview of the maximum duration of electricity storage needed to ensure demand is fully met for a given level of VRE penetration



SDES (<8hrs) is needed to reach 50-80% wind and solar share of electricity generation, 70-90% VRE penetration needs inter-day and inter-week LDES of up to 100-hour durations, and over 90% VRE penetration requires LDES with durations of 100 hours or more. The UK's share of VRE over time from NESO scenarios is laid over the top. The government's definition of 95% clean power generation by 2030 implies that by that date around 65-85% of electricity generation will be from wind and solar (depending on the scenario).[15] This suggests that more inter-day and inter-week LDES will be required and, in the higher scenario, some seasonal storage. The NESO FES pathways for 2050 give a similar range of VRE share of generation, up to 80%.[16]

Source: *Albertus et al. (2020)[17] with author additions to mark percentages of VRE generation in the UK based on data from NESO Clean Power 2030 scenarios (2025) for the 2030 ranges and NESO FES pathways (2025) for the 2050 range.*

15. DESNZ (2025) *Clean Power 2030 Action Plan*. Section 'Our pathway to 2030: Defining the clean power target', Figure 7: Generation in 2030 in the NESO 'Further Flex and Renewables' and 'New Dispatch' scenarios, compared to current generation (TWh).
16. NESO (2025). *FES 2025 Data Workbook*. The proportion of solar and wind in total electricity generation by NESO FES pathway are: 'Electric Engagement' 75-80%, 'Holistic Transition' 70-75%, 'Hydrogen Evolution' 65-70%.
17. Albertus et al. (2020). *Long-Duration Electricity Storage Applications, Economics, and Technologies*. Joule, Volume 4, Issue 1.

> Without energy storage or other flexibility, it has been estimated that the GB system will have a surplus of low-carbon power for around 50% of the hours in the year by 2030. Energy storage could reduce this surplus to ~20% of hours.[18]

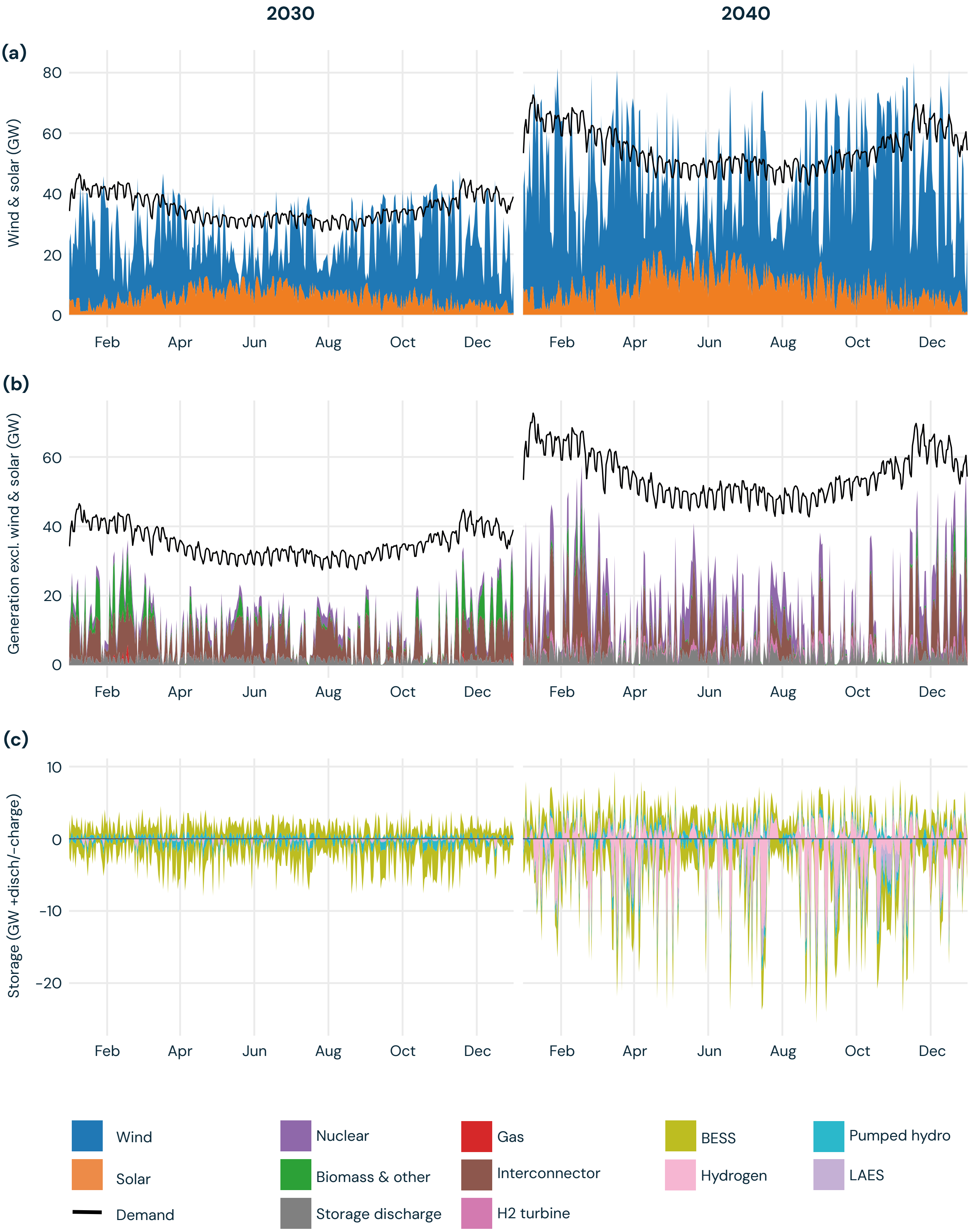
Increasing VRE penetration (Figure 3) creates an opportunity for larger volumes and longer durations of storage to act as absorptive capacity. By absorbing surplus power, storage assets improve the economic use of generation assets. This is particularly valuable given nearly all VRE assets receive government subsidies via Contracts-for-Difference (CfD) and the Renewables Obligation (RO).

In addition, by reducing curtailment and constraint payments, and avoiding over-build of solar and wind generation capacity, storage can contribute to lower system costs – by between £13bn and £24bn by 2050, according to a government study[19] – and thus lower electricity prices for consumers. LDES investment therefore has the potential to reduce electricity system costs and could contribute to downward pressure on inflation and interest rates.

In terms of system reliability, as VRE penetration increases, the scale of gaps in VRE generation also grows, with longer periods of reduced supply due to weather risk ('dunkelflaute') and larger gaps between peak demand and low supply events, due to correlated renewables output (Figure 3a). Storage, particularly inter-week or seasonal LDES, can help to bridge both types of gaps. This is shown in Figure 3b, where storage plays a more significant role in the generation mix in 2040 than in 2030, and in Figure 3c by the contribution of hydrogen in the 2040 system. Hydrogen is called on often, absorbing 19 TWh of surplus and discharging 6.5 TWh to the grid in 2040, operating at the deep, prolonged tails of the residual demand curve that short-duration batteries cannot bridge.

18. Brown et al. (2024). *Generating surplus: the challenges and opportunities of large-scale renewables deployment*. 'Potential surplus' is defined as hours in which the combination of solar, nuclear and wind power output exceeds the underlying electricity demand in Great Britain projected in 2030, in the absence of any 'system flexibility', i.e. without storage, flexible demand response, or interconnector flows between GB and its neighbours, and with no accounting also for transmission constraints within GB.
19. Department for Business, Energy & Industrial Strategy (BEIS) and AFRY Management Consulting (2022). *Benefits of long-duration electricity storage*.

Figure 3: Projected incidences of generation surplus and shortfalls in GB's electricity system in 2030 and 2040



Source: *Author modelling using PyPSA-GB. The results are modelled with full-network hourly optimisation using the 2010 weather year (a low wind year) under the NESO FES 2025 Holistic Transition pathway, solved in fortnightly rolling windows. Panel (a) shows solar and wind generation. Panel (b) shows generation from other dispatchable sources. Panel (c) shows the contribution of energy storage.*

> Several studies show the UK is likely to have fewer but much longer scarcity events in future.[20]

The scale of future surplus and shortfall events is illustrated in Figure 4, which gives the percentage of hours that Britain's power system will have residual demand or residual surplus, after accounting for wind, solar and must-run firm power (such as nuclear, biomass, waste-to-energy and hydro power) in 2030 and 2040 across 41 weather years.

Figures 4c and 4d illustrate the scale of residual demand and surplus under conditions of low wind output (the 2010 weather year), and the potential role of storage in filling the gap and absorbing the surplus, based on cost-optimisation modelling.

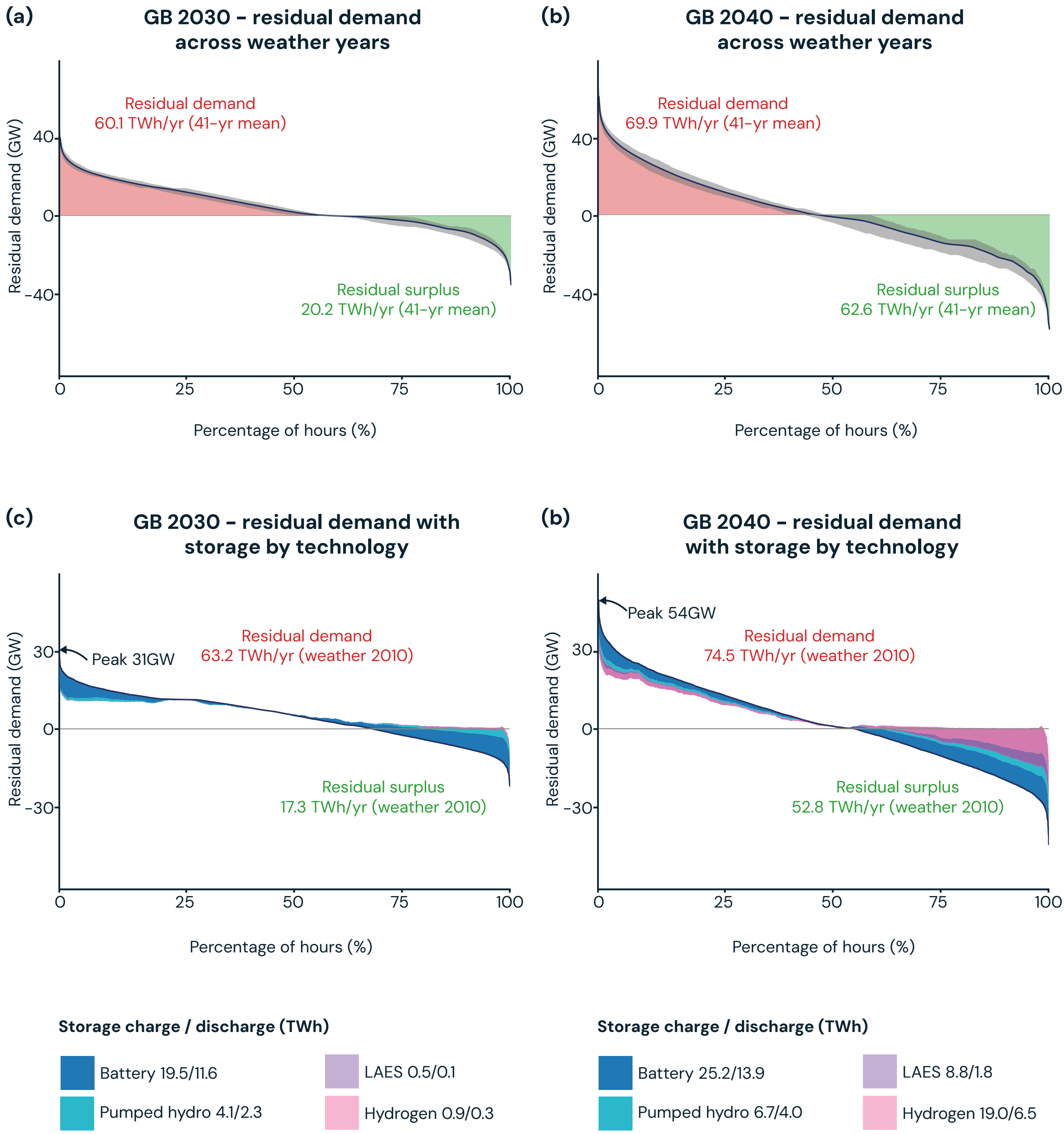
Annual residual demand grows from 63 TWh/yr in 2030 to 75 TWh/yr in 2040, while annual surplus grows even faster, roughly tripling from 17 TWh/yr in 2030 to 53 TWh/yr in 2040. Short-duration BESS shaves the peak and absorbs some surplus: in 2040 it cuts residual demand by only about 13% (from 54 to 42 GW) and absorbs about 40% of the surplus. Only with LDES, including hydrogen, is the surplus fully absorbed and residual demand reduced further, although not completely.[21] This indicates that the most cost-effective way to fully meet demand may involve LDES working alongside other resources including interconnectors[22] and consumer-led flexibility, while low-carbon fuels (like gas CCS or bioenergy CCS) or possibly continued use of unabated gas may also be needed to provide full supply back-up.

20. Bloomfield (2025). *Reasonable worst-case stress-test scenarios for the UK energy sector in the context of the changing climate*, Committee on Climate Change (CCC). DESNZ (2023). *Exploring Reliability Standard Metrics in a Net Zero Transition*.

21. Generation, storage and hydrogen capacities are fixed exogenously to the FES 2025 Holistic Transition pathway. The high absorption in 2040 reflects FES-planned hydrogen, which is built also for industrial and heat demand lying outside an electricity-only model.

22. Interconnectors will continue to serve as a source of dispatchable power in the UK's electricity mix and will impact how much LDES capacity is required. In 2025, net electricity imports via interconnectors accounted for 29.7 TWh or roughly 9% of the UK's total electricity demand (DESNZ, 2026). In future, as the electricity systems of the UK and its European neighbours become more reliant on weather-dependent renewables, these countries' electricity supply and demand are likely to be more correlated and the contribution of interconnectors to ensuring system reliability via imports or being able to absorb surplus renewables to export may be less significant. See DESNZ (2026) *Energy Trends: March 2026*.

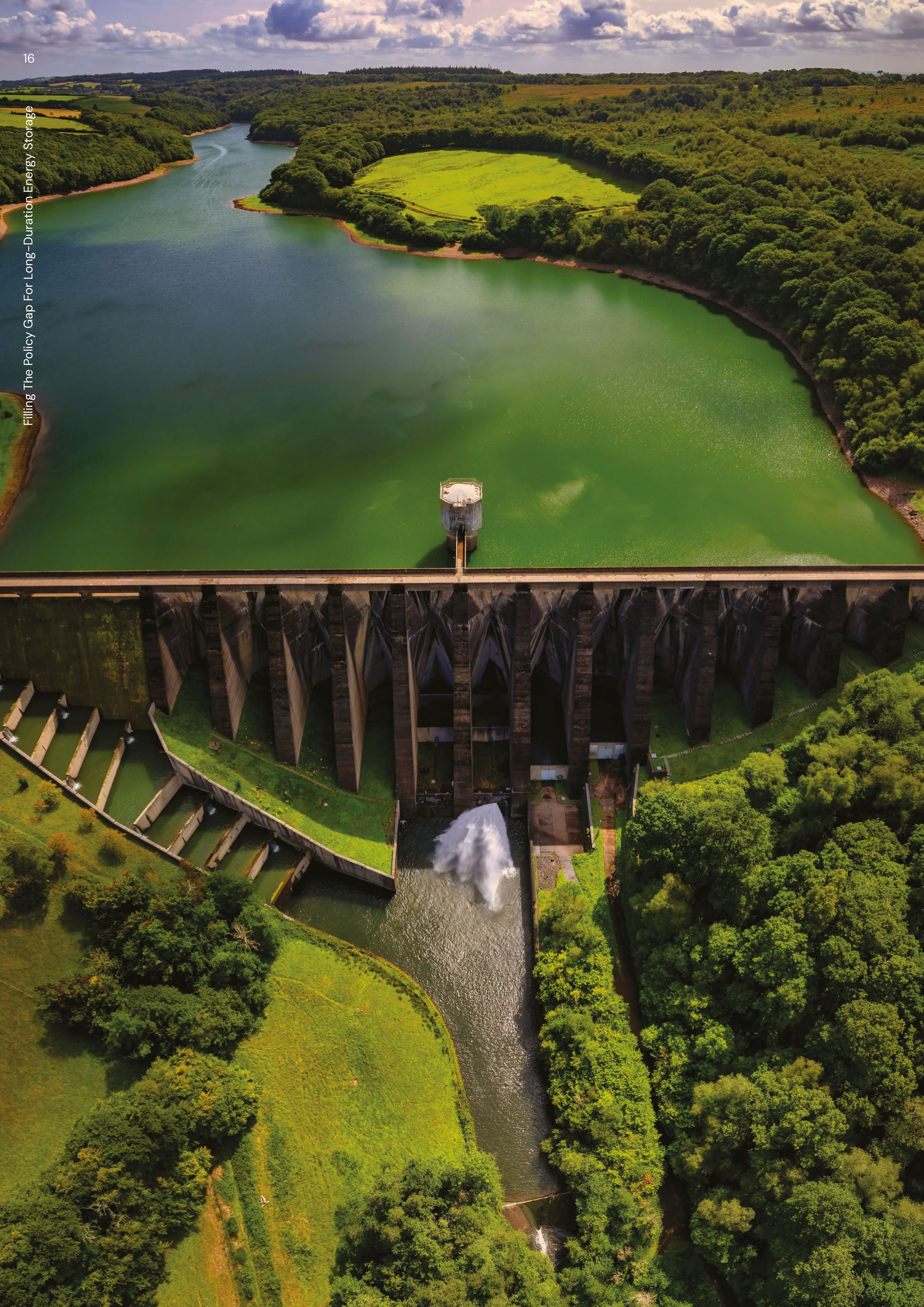
Figure 4: Residual demand curve for the GB electricity system in 2030 and 2040, showing the proportion of time in energy deficit or surplus, with and without energy storage



Source: *Author modelling using PyPSA-GB. Residual demand is electricity demand minus wind, solar and must -run firm generation (nuclear, biomass and other low-carbon), sorted from the highest-deficit hour (left) to the largest-surplus hour (right); red = residual demand, green = residual surplus.*

(a) and (b): 41 weather years (1985–2025) under the NESO FES 2025 Holistic Transition pathway, single-node model, mean (navy line) and P10–P90 range (grey band).

(c) and (d): whole-network dispatch for weather year 2010 (low wind output) under the same pathway, with fortnightly rolling windows.

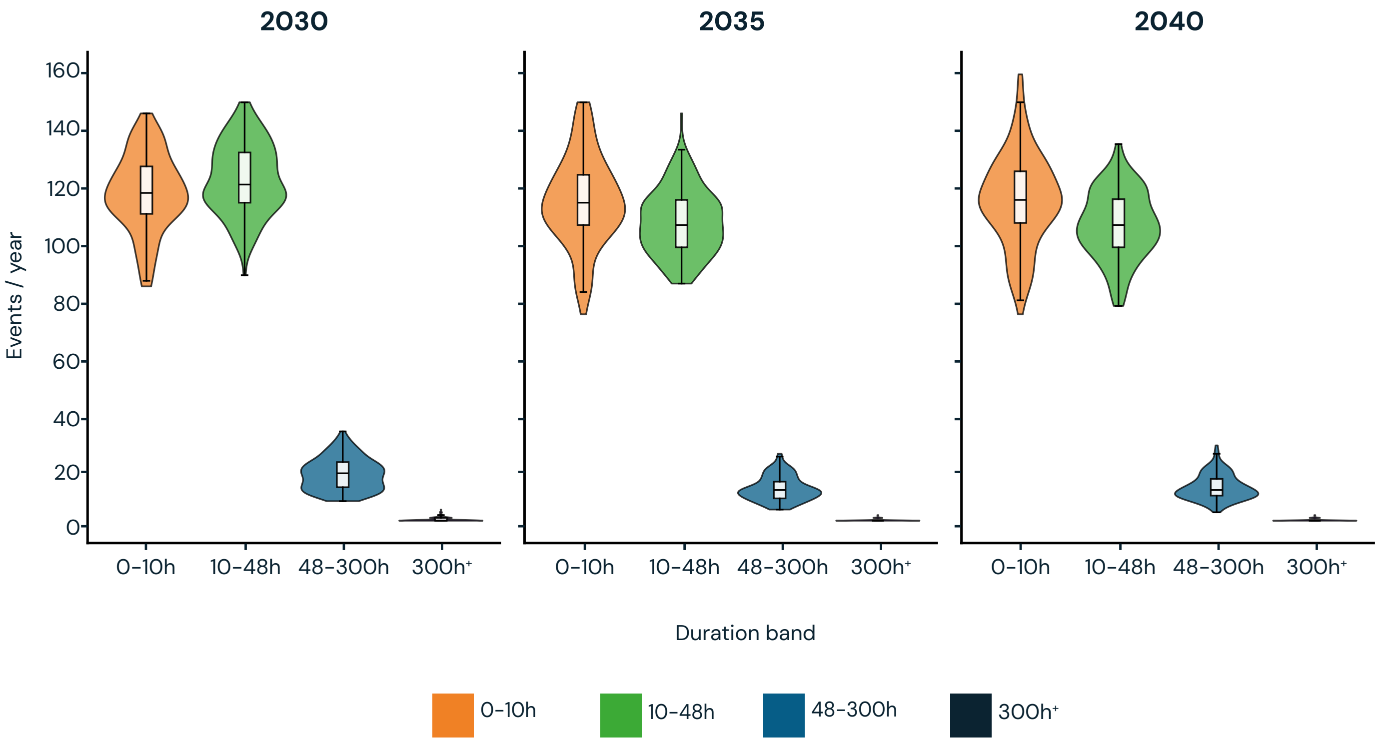


How the need for energy storage varies across duration categories

The projected frequency and duration of VRE deficit events can indicate how often each storage duration category is likely to be needed to meet residual demand (alongside interconnectors, demand-side flexibility and low-carbon fuels). Figure 5 shows the frequency of VRE deficit events (where demand exceeds generation from VRE plus firm generation) of 0-10 hours, 10-48 hours, 48-300 hours and over 300 hours' duration in the future, modelled using multi-decadal weather data and four scenarios of the UK's future energy system. The analysis indicates that Deficit events lasting 0-10 or 10-48 hours will each occur roughly one hundred times per year, events lasting 48-300 hours will occur roughly ten times per year, and events lasting more than 300 hours will occur roughly once a decade.

Therefore, the expectation is that shorter-duration storage technologies including BESS, PSH and CAES or LAES can be used around a hundred times per year, while technologies for inter-week and seasonal LDES will be used much less frequently.

Figure 5: Frequency of VRE deficit events of different durations in GB in 2030, 2035 and 2040



Source: *Author modelling of the hourly balance between Great Britain's electricity demand and its low-carbon generation across the full ERA5 weather record (1985-2025) under four NESO Future Energy Scenarios 2025 pathways. The x-axis shows the duration of the VRE deficit event. The y-axis shows the distribution of the number of deficit events per year, over 41 years of weather data with the demand and technology mix of the four different NESO FES pathways. A period of VRE deficit is defined as when demand exceeds available generation from VRE plus firm generation (including nuclear, biomass, waste-to-energy, biogas, large hydro, landfill gas, advanced biofuel, sewage gas and geothermal).*

The need for LDES policy

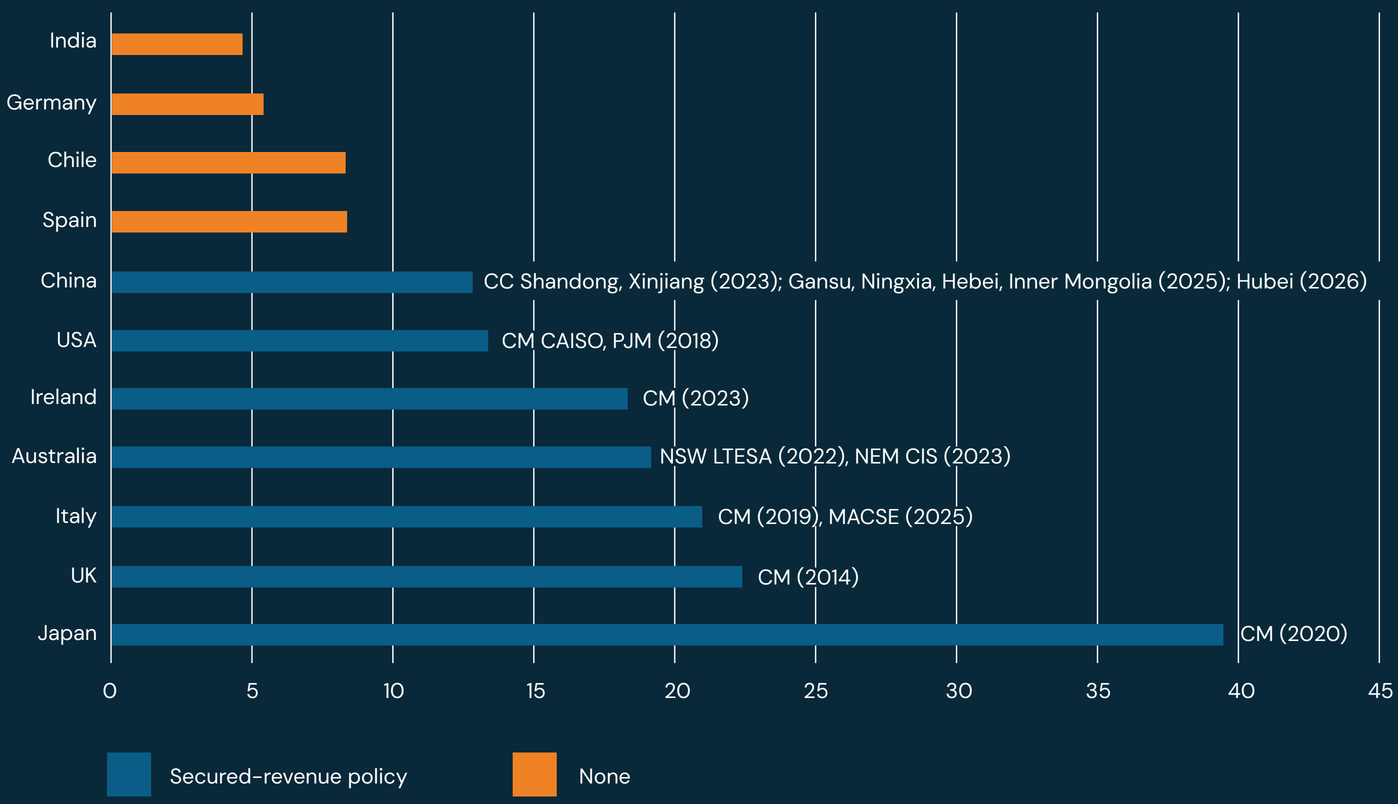
> LDES investment faces greater difficulties than short-duration storage in two key areas: revenues are more uncertain, and the technologies are less well-established.

These challenges are likely to be more pronounced for storage of longer durations, given greater revenue uncertainty and fewer commercially proven technologies. Without policy support, LDES has a 'missing money' problem, where market revenues are likely to be insufficient to recover costs. This could lead to underinvestment compared to the level that would be cost-effective for the system when the full range of roles that LDES can play are taken into account – including improved system stability, reduced curtailment, lower balancing costs, and less need for fossil fuel peaking plants.[23]

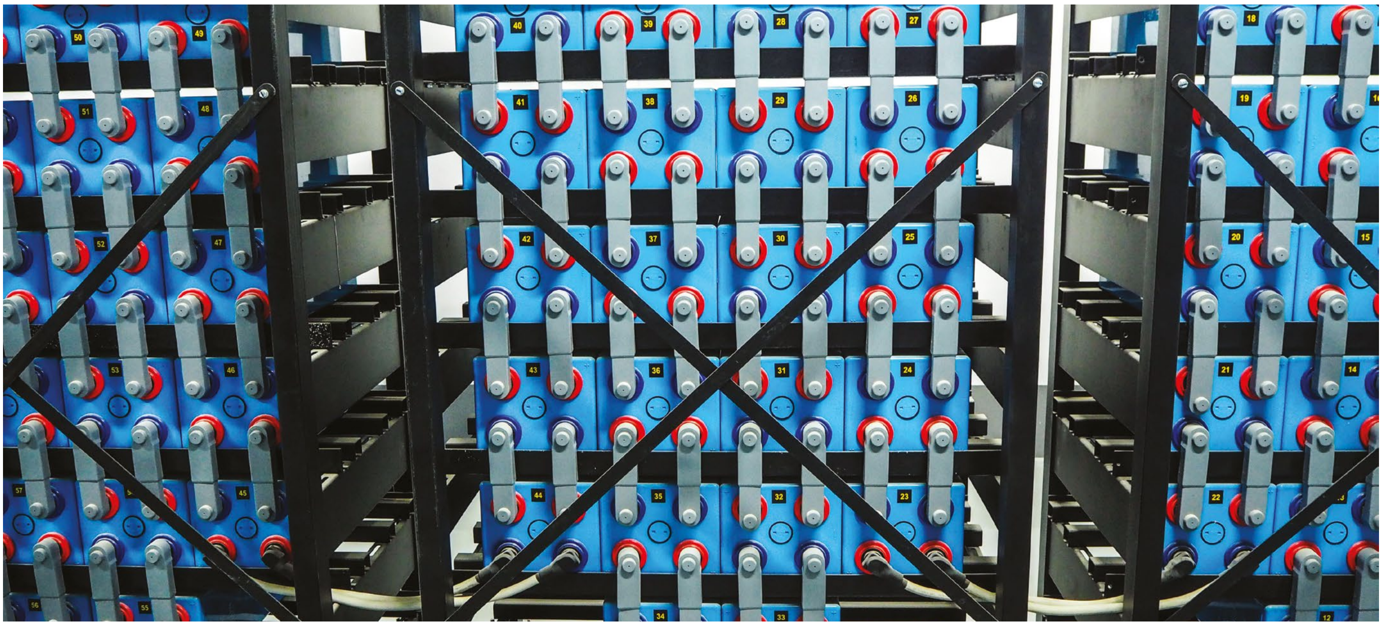
International comparison of energy storage policies and deployment rates suggests that having mechanisms that contribute to revenue stabilisation (such as a capacity market open to energy storage or a dedicated storage deployment policy), in addition to allowing energy storage to engage in arbitrage and ancillary services, makes a positive difference to the level of storage deployment (Figure 6).

23. Many of the challenges facing LDES deployment can be understood in terms of market failures. These include: missing long-term markets for long-duration flexibility value, inter-seasonal price spreads and system adequacy beyond short horizons; imperfections in capital markets; system and carbon externalities; imperfections in information about future power prices, system needs for flexibility, policy evolution, costs and performance for novel LDES technologies; learning spillovers for newer technologies; and market failures in operationalising large LDES projects, like PSH, due to their very large upfront costs, long build-times, and as they cannot easily be developed in stages. At the same time, the role of LDES in ensuring system resilience and security of supply is one that markets are not typically well-suited to addressing, given the trade-offs between efficiency and resilience. See also Ofgem (2026). *Assessment of impacts of the proposed LDES portfolio*, 'Barriers and market failures'.

Figure 6: Comparison of energy storage deployment in countries with and without secured-revenue policies



Source: *Author calculations of energy storage capacity as a proportion of total VRE capacity (%, MW) using operational capacity data on solar, wind and pumped hydro storage from Global Energy Monitor (2026), and data on battery energy storage from Modo Energy and other sources (2025-26). 'Energy storage capacity' refers to the total of pumped hydro and battery capacity in each market. The markets chosen are the largest electricity markets for which comparable data could be obtained. The data labels give the name of the policy, the relevant sub-national power market (where it is not a national policy), and the date of the policy's introduction. Acronyms in the data labels are: CC, capacity compensation; CM, Capacity Market; CAISO, California Independent System Operator; PJM, Pennsylvania-New Jersey-Maryland Interconnection; NSW, New South Wales; LTESA, Long-Term Energy Service Agreements; CIS, Capacity Investment Scheme; MACSE, Mechanism for the Acquisition of Storage Capacity.*



Revenue stabilisation policies are likely to be even more important for LDES than for SDES assets. LDES assets have higher upfront capital costs than shorter-duration assets and, for inter-week and seasonal LDES to be available for scarcity events, they may not be able to fully cycle as frequently to maximise merchant revenues. LDES revenues are highly uncertain in the following ways:

- Demand for LDES is harder to predict than that for shorter duration batteries as they are needed less frequently (as shown by Figure 5); this uncertainty increases for LDES of longer durations.
- LDES revenues depend on the interactions with generation and flexibility technologies in the electricity system, whose future deployment levels are uncertain. This is further exacerbated by variable demand and weather-dependent VRE output.
- LDES revenues can be influenced by future changes in policy or market design.

The uncertainty across these different factors is great over the long potential lifetime of an LDES asset, typically two or more decades. Less certain revenues, combined with long build times for many LDES technologies and the fact that most LDES technologies are novel and pre-commercial, makes the business model for LDES unattractive without a policy to stabilise revenue.

The government has recently introduced or is developing such policies to encourage investment in the long-duration, low-carbon flexible capacity the UK needs for the future: the LDES Revenue Cap-and-Floor Mechanism (based on the successful Cap-and-Floor model for interconnectors), the Dispatchable Power Agreement for gas with CCUS, and the Hydrogen to Power Business Model currently in development.[24] With the LDES Revenue Cap-and-Floor Mechanism, the UK is a world leader in introducing policy support specifically for LDES.

Innovation policy is also required in the immediate term given the diversity and novelty of LDES technology options (Annex 1). Aside from pumped storage hydro and lithium-ion batteries, most LDES technologies are operational only in demonstration projects and do not yet have a track record of improvement and cost reduction through learning by doing. Strategic investment and scale demonstrations are needed before large-scale market take-up, to help encourage early investment in newer LDES technologies and assess which technologies will best meet the needs of the UK's future energy system.[25]

Possible innovation policies could include introducing deployment contracts of limited duration and scale for novel LDES, such as five-year pilot projects, or a programme of accelerated demonstration and testing of megawatt-scale installations over the next five years. The UK should engage in international cooperation as part of this, exchanging lessons about what works with other countries testing LDES technologies, for example through Mission Innovation's clean power mission which the UK co-leads.[26]

24. Ofgem (2025) *Long Duration Electricity Storage Technical Decision Document*, DESNZ (2022) *Carbon Capture, Usage and Storage: Dispatchable Power Agreement business model summary*, DESNZ (2025) *Hydrogen to Power Costs and Barriers*.

25. See Grubb (2015). *On the distinguishing features of energy systems and innovation.*

26. Mission Innovation Green Powered Future Mission.

How appropriate policies could vary across LDES duration categories

> Different policies are likely to be needed to support LDES in each of the duration categories, due to differences in investment and operational risks, the services each LDES category can provide and the markets they can participate in.

At a high level, the options for investment are market-based mechanisms such as the Revenue Cap-and-Floor or Capacity Market, or more extensive state involvement such as through a strategic energy storage reserve. An additional choice is between the UK's existing self-dispatch model and centralised dispatch.[27] The choice between these options depends on considerations around effectiveness in enabling deployment at levels consistent with system needs, availability of the assets when needed to ensure security of supply, and contribution to the system's operational efficiency.

Here we outline what could be the most appropriate approach to policy in each of the duration categories, with a focus on the degree of state involvement in investment and operational control.

27. **Centralised dispatch**, common in US markets, means the system operator optimises and instructs the physical output of generators, storage and some loads based on bids, offers and network constraints. **Self-dispatch**, the model in Great Britain, means market participants decide their own production and consumption schedules through bilateral and exchange trading, while NESO intervenes mainly through the Balancing Mechanism close to real time.

Inter-day LDES

> Inter-day LDES (10-48h) primarily serves to provide market liquidity and capacity adequacy.

It will rarely be critical to security of supply, as there will be multiple options available to manage shortfalls of this duration, but it can fulfil other useful roles and potentially participate in the same markets as SDES.

The frequency with which it will be needed to help meet residual demand in the future energy system is around 100 times per year – as often as short-duration batteries but with a larger volume of energy able to be charged and discharged with each use, implying that significant value will cycle through this category of LDES. Market revenues can therefore make up a significant element of the business case for inter-day LDES, suggesting that with appropriate policy support, private investment could bring forward enough capacity and direct state investment is not needed.

In terms of operation, self-dispatch by inter-day LDES assets based on price signals and forecasting of scarcity events is likely to remain sufficient. Forecasts using demand and weather data are accurate for periods a day or two ahead, minimising the risk that inter-day LDES will be unavailable for when it is needed.

The government previously considered and rejected the option to target LDES deployment through a reformed Capacity Market, on the grounds that the mechanism, even in a modified form, would not be sufficient to attract investment in LDES given its high capital costs and technology uncertainty.[28] The Capacity Market is technology agnostic by design, and LDES would have to compete against other technologies that could provide available capacity at lower cost while not providing all the other system services that LDES could provide. This could prevent the Capacity Market ever providing contracts at a high enough price to enable LDES deployment. Creating a separate 'pot' for different types of LDES to compete against each other in the Capacity Market would solve this problem, but would be roughly equivalent to the LDES Revenue Cap-and-Floor policy without the cap.

> The LDES Revenue Cap-and-Floor seems to be an appropriate mechanism to address the barriers to deployment faced by LDES in this duration category.

The mechanism avoids the problems LDES would face competing in the Capacity Market by holding auctions ringfenced around LDES technologies. However, we suggest that the policy design should be adjusted to bring forward the greater diversity of LDES technologies and duration types that are likely to be needed for the UK's future energy system.

28. DESNZ (2024), *Long duration electricity storage consultation.*

The 'Window 1' auction for contracts under the Revenue Cap-and-Floor aimed to procure LDES capacity to be operational by 2030 or 2033. It attracted over 70 bids with a duration range of 8-32 hours. Setting a minimum 8-hour duration, a high technology readiness requirement and minimum capacity criteria[29] has limited the diversity of applications: lithium-ion batteries make up around two-thirds of the eligible capacity, with a handful of pumped hydro and flow battery projects, and one CAES project.[30] From this, Ofgem has selected projects of longer duration assets, across a range of technologies and locations, which it proposes for investment. In total these would add 7.6 GW or 136.9 GWh of storage capacity to the system.[31] If all of this capacity receives support and is deployed, this would provide significant inter-day flexibility in line with the government's 2030 target for LDES.

The future Window 2 auction is intended to procure the LDES capacity that will be needed in 2035 and 2050, when the system will need longer storage durations. Auctions from Window 2 onwards could divide competition into 'pots' of different minimum durations to procure the range of LDES capabilities needed in the future (analogous to the auction pots that have allowed Contracts for Difference to support renewable generation technologies of differing maturity). The duration and capacity to target with each pot could be based on the modelled relationship between VRE penetration and storage duration in the UK and/or on the duration taxonomy proposed earlier: pots for inter-day (10-48 hours duration) and inter-week (48-300 hours) storage, or potentially for subdivisions within those categories. However, as suggested below, inter-week storage may require additional regulation, and seasonal storage may benefit from a substantially different approach.

The extended LDES Cap-and-Floor Mechanism may also need to allow more novel technologies to take part in future allocation windows, given many of these have the potential to operate efficiently as inter-week or seasonal options and currently do not have a route to market through this mechanism. This could be achieved by lowering the TRL requirement to 7, so that piloted technologies, such as liquid air energy storage or non-vanadium flow batteries, can take part. The minimum capacity requirement for projects could also be loosened to allow projects smaller than 50 MW to compete for a limited number of contracts (for example, up to ten awards available). This would help emerging technologies access revenue support to operate, scale up and build supply chains in the UK, without dramatically increasing the administrative burden for Ofgem.

With very few countries around the world implementing policies to deploy LDES, there are few examples of alternative LDES market mechanisms for the UK to consider. Countries which have capacity-based compensation mechanisms for energy storage are procuring storage of less than 8-hours' duration. Of these, Italy's MACSE scheme is interesting as it combines long-term revenue stabilisation with a strong element of centralised operational control by the system operator.[32] Australia's new Electricity Services Entry Mechanism, being rolled out from 2027, will offer long-term contracts for 'firming' services which could be an interesting example to watch.[33] Continued international benchmarking of policy options and the pros and cons of different market-based deployment policies for LDES should be further explored.

29. Window 1 of the Cap-and-Floor requires 'stream 1' projects for 2030 delivery to have a minimum capacity of 100 MW and at technology readiness level 9 (TRL 9; market-ready, commercially scaled and already in operation in the UK or internationally), and 'stream 2' projects for 2033 delivery to have a minimum capacity of 50 MW and TRL 8 (proven to work commercially beyond demonstration stage projects).

30. Modo Energy (2025). *LDES Cap & Floor scheme: The projects in the running and how Ofgem will rank them.*

31. Ofgem (2026) *Consultation Window 1: Minded-to decisions – Long Duration Electricity Storage.*

32. MACSE (Mechanism for the Acquisition of Storage Capacity) is Italy's long-term capacity procurement scheme for standalone energy storage through competitive auctions, run by Terna, the transmission system operator. Successful projects have system-oriented dispatch obligations, including mandatory participation in the dispatching services market which Terna uses to maintain system security. The first auction round in 2025 procured 10 GW of BESS, awarding 15 year contracts for fixed annual payments to projects of 7 hours' duration on average. See Modo Energy (2025) *MACSE Results.*

33. Following its National Electricity Market Review, Australia is setting up a new Electricity Services Entry Mechanism (ESEM) which will replace existing schemes from 2027. The ESEM will auction long-term contracts, based on targets determined by reliability requirements and emissions goals, for key services: (1) bulk zero emissions energy; (2) shaping, i.e. moving electricity to the time of day it is needed (demand-side flexibility, batteries); and (3) firming, i.e. long-duration dispatchable capacity. A fourth category of essential system services (e.g. frequency and voltage regulation, inertia, system strength) is cross-cutting, where projects providing the other services are expected to also be able to provide this. The government is currently consulting industry on the design of these contracts. The contracts for firming services could be an interesting comparator for the UK. See Department of Climate Change, Energy, the Environment and Water (2025), *National Electricity Market wholesale market settings review.*

Seasonal LDES

> Seasonal LDES (>300h) primarily provides inter-seasonal energy balancing, a service which it can uniquely provide, making it critical to security of supply.

LDES of this duration is likely to be needed roughly once a decade to fill the longest-lasting shortfalls between demand and generation from variable and firm resources. Its use primarily for high impact but very low probability events means it will have considerable revenue uncertainty. Even with policy support, such as a dedicated >300h duration 'pot' within the LDES Revenue Cap-and-Floor mechanism, it may not be an attractive enough proposition to private investors to incentivise enough to be built in time for when it is needed. Auctions can fail, as the fifth auction round for offshore wind Contracts for Difference illustrated. Equally, projects can be cancelled when input costs rise.[34] Given the importance of seasonal LDES for security of electricity supply in the UK's highly electrified future economy, uncertainty around investment could translate into significant economic risk.

Operational considerations are important too. The Capacity Market has successfully supported security of supply by providing payments for assets to be available during system stress events. This approach is well suited to thermal generation, where capacity availability is largely separate from fuel procurement. For LDES however, the key challenge is not only capacity availability but also the availability of stored energy. A capacity payment can ensure that an LDES asset exists and is technically available, but it cannot guarantee that the asset maintains sufficient charge to respond during a prolonged emergency. An LDES Cap-and-Floor Mechanism extended to support seasonal storage would involve similar uncertainty.

Ofgem is exploring how to mitigate the risk of LDES assets being uncharged when they are needed with the design of the licence conditions for LDES Revenue Cap-and-Floor projects.[35] Under the current system of self-dispatch, the risk of unavailability could be partially mitigated by thorough regulatory oversight, including spot-checks and fines, combined with effective forecasting of scarcity events by LDES operators. However, residual risk would always remain due to the potential for misalignment between LDES asset owners' interest in maximising profit, and the public interest in security of supply.

> Given the potentially critical role of seasonal LDES in ensuring security of supply, and the likely rarity of its use, there is a good case for putting it in a strategic reserve.

With this approach, direct state investment would ensure the capacity needed to ensure security of supply is procured and maintained. High capital costs and uncertain revenues would not be translated into investment uncertainty. Operation of the assets by NESO, outside the electricity market, would be entirely for the purpose of meeting security of supply and system resilience needs. The assets would be state-owned, either directly by the UK Government (Department of Energy Security and Net Zero or the Treasury) or by a state-backed entity, possibly Great British Energy or a non-profit agency similar to the European central oil stockholding entities.

A state-owned strategic energy storage reserve is likely to provide this greater security of supply at comparable or lower cost than market-based approaches. Procurement of storage capacity for the strategic reserve would be competitive, just as it is with a market-based mechanism. Construction and operation would be financed by government through taxation or a levy on electricity bills, rather than through private investment. This would be likely to benefit from lower cost of capital than private financing, potentially resulting in significant savings given the high upfront costs of the assets.

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34. For example, while the GB CfD scheme includes penalties for non-delivery, projects have been cancelled after receiving CfDs. Notable recent examples are TwinHub (CfD awarded in Allocation Round 4 in 2022 and cancelled in March 2026) and Hornsea 4 (CfD awarded in Allocation Round 6 in 2024 and cancelled in 2025). See Renewables Now (2026), *First-ever UK floating wind CfD for TwinHub project terminated* and Ørsted (2025), *Ørsted to discontinue the Hornsea 4 offshore wind project in its current form.*

35. Ofgem is seeking input on operational safeguards for assets awarded LDES cap-and-floor revenue support, to ensure that they 'operate as LDES' to maintain long-duration capability and readiness over time. Ofgem (2026). *Call for Input on LDES Draft Special Licence Conditions.*

Differences in operational costs between a private- or state-owned LDES asset are ambiguous. Storage in a strategic reserve would sit outside the market and only operate rarely, during emergencies. Privately-owned seasonal LDES would also most likely be strictly limited by regulation in its market participation, to remain ready for emergencies, offsetting any signals for operational efficiency that the market might provide. It is unclear how paying private seasonal LDES asset owners a long-term contract of fixed revenue to remain available, combined with regulation and fines to limit the assets' participation in the market, would achieve any savings compared to the state directly owning an LDES asset and covering the operation costs from the government's balance sheet.

While no country currently has a strategic energy storage reserve, international comparators exist. Ireland's EirGrid proposed what is effectively a strategic reserve as one of its options for a LDES Procurement Mechanism, noting its benefits but that implementation would require regulatory change to allow the transmission system operator to directly operate assets.[36] Some countries including Australia, China and Germany, have grid-owned energy storage assets that support the functioning of the system.[37] Critically, many countries have strategic petroleum reserves (including the UK) and/or gas reserves to ensure energy security. These are stockpiles kept for emergency use when energy supplies are disrupted, rather than relying entirely on the market. As illustrated in Figure 7, as the UK moves to an electrified, renewable-powered economy and its reliance on fossil fuels decreases, the need for an equivalent strategic reserve to support electricity security becomes more apparent. For this reason, the UK's National Infrastructure Commission has recommended the development of a strategic reserve that can be used to generate 25 TWh of electricity in 2040, controlled by the government, to support both energy and economic security.[38]

The UK's difficulties with market-driven gas storage provision illustrate the security advantages of state ownership and operation in a strategic reserve. While the UK has strategic petroleum stocks equivalent to at least 90 days of net oil imports (or 23 days of national oil use in a no-imports scenario),[39] it does not hold strategic gas reserves. The shortcomings of a market-only approach were highlighted when Centrica decided to close Rough, the UK's largest gas storage facility, in 2017. This left the UK highly reliant on short-term imports and more exposed to volatile gas prices during the 2021-22 energy crisis than European neighbours with strategic gas reserves. The UK Government has pushed Rough to reopen, but its capacity today of around 1.5 billion cubic metres (around 16 TWh)[40] is still less than half its historic peak of 3.3 bcm (around 35 TWh or nine days of national gas demand).[41] The government has not yet explained how it will replace the storage capacity Rough previously provided.

36. EirGrid's 2025 consultation on a LDES Procurement Mechanism proposes a 'Full TSO Control' option which is effectively a strategic storage reserve: LDES assets operate without market access but under contract of full control by the TSO, which would decide when the LDES assets charge/discharge, aiming to maximise the value of LDES assets in terms of minimising re-dispatch and supporting system operations. The LDES asset has only this one revenue stream. The consultation's recommended option is a revenue cap-and-floor mechanism for energy storage with a minimum duration of 4-hours. EirGrid (2025). *Long Duration Energy Storage (LDES) Procurement Mechanism Consultation*.

37. In China, the costs of grid-owned storage assets are shared among all users. In Germany, 'grid booster' batteries are treated as part of the grid and used to ease transmission congestion; Australia has a similar model.

38. House of Lords Science and Technology Committee (2024), *Long-duration energy storage: get on with it*, and House of Lords Science and Technology Committee (2023) *Corrected oral evidence: Long-duration energy storage,* Evidence Session No. 7, 24 October 2023, oral evidence by Nick Winser, Commissioner of the National Infrastructure Commission (question 53). 25 TWh is chosen as the equivalent of about two months' worth of the non-renewable part of the UK's energy system in 2040. Technology options discussed for the strategic energy reserve include hydrogen (possibly with natural gas in the near term), compressed or liquid air storage, or flow batteries.

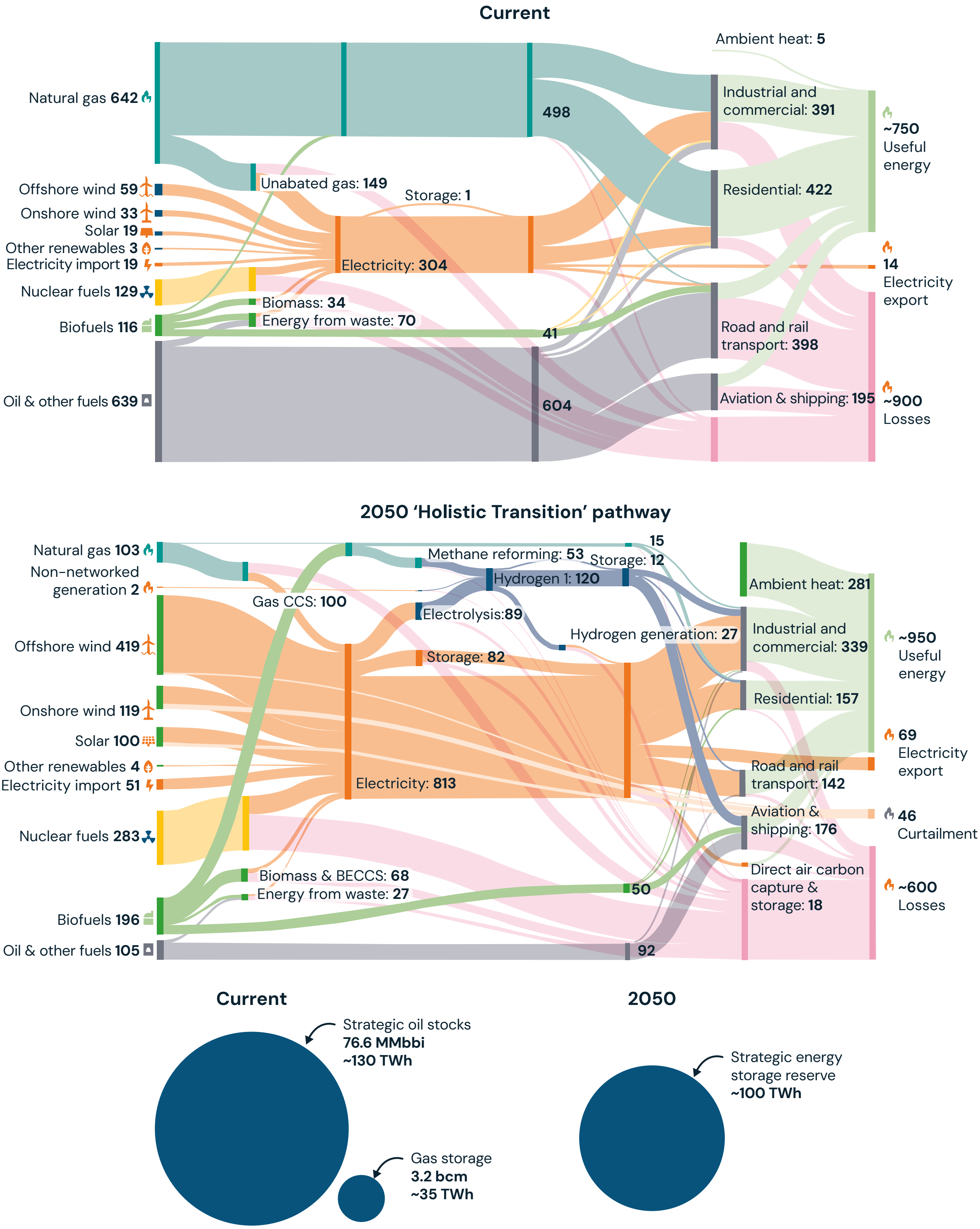
39. UK Oil Watch (2026). *UK Diesel Reserves: What 23 Days Actually Means*.

40. Ofgem (January 2025). *GB gas storage facilities in 2025*.

41. iNews (2022). *UK's largest gas storage site Rough unlikely to hit capacity by Christmas despite hopes it would ease crisis*.

42. Sankey diagrams from NESO (2025) FES: Oil stocks data from DESNZ (2026): *UK joins IEA members in coordinated oil stock release,* GOV.UK; gas storage capacity from UK Parliament (2025): *Natural Gas: Storage (UIN 55907)*; and the strategic energy storage reserve capacity is based on the estimate by the Royal Society (2023) of 100 TWh of LDES need by 2050.

Figure 7: Energy use in Great Britain, today and in 2050



***Source:** Sankey diagrams of GB's current and 2050 energy system from NESO FES (2025), with author's addition of current oil stocks, current gas storage and high-end estimate of strategic energy storage reserve capacity.[42] 'Oil and other fuels' refers to oil or diesel (the largest sub-category in the current energy system), waste-to-energy, other small-scale thermal generation, and renewables such as geothermal or marine.*

Inter-week LDES

> Inter-week LDES (48-300h) provides a range of services - capacity adequacy, system resilience and market liquidity.

It is likely to be needed infrequently, around 10 times per year, to help meet VRE generation deficits. (As shown above, this is an order of magnitude less often than inter-day LDES, and an order of magnitude more often than seasonal LDES). The relative infrequency with which inter-week LDES would be needed creates considerable revenue uncertainty. This, combined with the high up-front costs and novel technologies in this LDES category, make policy support necessary to help de-risk investment, but it is uncertain whether private investors will deploy inter-week LDES to the level needed by the system, even with policy support.

Given these characteristics, it is unclear whether a market-based deployment policy such as an extended Cap-and-Floor Mechanism or direct state investment, ownership and operation through a strategic reserve is more appropriate for inter-week LDES. While the latter approach would reduce investment and operational risks, important for security of supply, deploying inter-week LDES as part of a strategic energy storage reserve would prevent these assets from providing their full potential range of system services. It may be preferable for inter-week LDES to remain in the market, with appropriate policy support and regulation. Further work is needed to assess the appropriate policy approach to deploy this category of LDES.

A market-based approach to deployment of inter-week LDES could consist of a modified LDES Cap-and-Floor scheme that includes an auction 'pot' for assets of minimum 48h duration. Centralised dispatch could be used to ensure the assets' availability for operation when needed for security of supply, with the unavoidable trade-off that prioritising their use in this way would reduce the system benefits that could arise from more frequent cycling through charging and discharging, and the revenues available to these LDES assets.

An alternative option is to use a regulated asset base (RAB)[43] model to deploy inter-week LDES, in which the assets would receive a regulated return largely independent of market outcomes. This could overcome the barrier of high up-front capital costs and help attract long-term private investment, potentially more effectively than the Revenue Cap-and-Floor policy given its greater certainty over returns. However, allowing these assets to participate in the market could pose significant competition risks for other flexible assets (such as demand-side flexibility or SDES) – more so than the LDES Revenue Cap-and-Floor, given the RAB assets' relative independence from market revenues.

43. A regulated asset base (RAB) is used in the UK energy sector for large, capital-intensive infrastructure assets that provide essential public services and have monopoly characteristics: electricity and gas transmission and distribution networks, new strategic energy infrastructure, including nuclear power stations like Sizewell C and, more recently, RAB-style frameworks for CCUS and hydrogen transport and storage networks to help attract long-term private investment. For further context see DESNZ (2023) *Energy Security Bill factsheet: Carbon dioxide transport and storage regulatory investment model;* DESNZ (2023) *Hydrogen transport and storage infrastructure: minded to positions.*

Conclusion

Understanding energy storage in terms of four different duration regimes – short-duration (0-10 hours), inter-day (10-48 hours), inter-week (48-300 hours) and seasonal (>300 hours) – based on the services and markets addressed and the relevant technologies, can help to identify what type of storage is needed when, how often, and the policies to support its deployment and operation.

The UK is doing comparatively well by international standards in the deployment of SDES, particularly BESS for intraday operations, although operational challenges exist. The picture is different for LDES. As the UK's electricity system becomes more dominated by wind and solar power and the economy electrifies, there is an increasing need for longer-duration energy storage capable of absorbing large volumes of surplus renewable energy and of discharging power over periods of several days to weeks to support security of supply. Current policy to support LDES deployment risks falling short by not incentivising investment in enough storage capacity of longer durations – particularly inter-week or seasonal LDES – or failing to ensure these assets are operated in line with system needs, particularly when it comes to ensuring security of supply during rare but high impact scarcity events.

There are two broadly defined policy routes to deploying LDES: market-based approaches, in which we focus on the option of a reformed Revenue Cap-and-Floor policy, and state-ownership and operation of a strategic energy storage reserve. From a high-level comparison, we conclude that for inter-day LDES, an extended Revenue Cap-and-Floor Mechanism could encourage adequate investment and efficient operation, while for seasonal LDES, inclusion in a strategic reserve could ensure security of supply more effectively, potentially at comparable or even lower cost. For inter-week LDES, where the right approach is least clear, a market-based deployment policy combined with centralised dispatch could strike a balance between ensuring assets' availability to contribute to security of supply and allowing them to contribute to capacity adequacy and market liquidity. These initial conclusions should be tested and substantiated with further analysis.

This area of policy development would benefit from further research into several areas. Existing estimations of future LDES needs can be built upon by developing a sensitivity analysis for the level of economic LDES capacity, of different durations, under varying scenarios of the future UK energy system, including testing assumptions about the role of short-duration BESS, demand-side flexibility, interconnections and generation technologies that could compete with LDES. Estimates of LDES need should also be stress-tested for the impact of rare weather events, using multi-decadal datasets of historic weather conditions and future climate projections to determine the level of resource adequacy need in a VRE-dominated power system and electrified economy, and the level of acceptable risk in meeting this need. Another area of enquiry could be to identify which LDES technologies are likely to have higher learning rates and to be well-suited to the services needed in the UK's future energy system. Further review of international policies on LDES could provide new ideas for policy design. Lastly, further research is needed into the relative effects on system costs of LDES and low-carbon flexibility compared to thermal peaking capacity.

Annex: Table of LDES technology options[44]

Technology type	Intraday Electrochemical Energy Storage	Intraday Compressed Gas Energy Storage	Intraday Pumped Heat Energy Storage	Multi-Day Energy Storage	Thermal Energy Storage (TES)
Description	Advanced chemistry batteries, e.g. sodium-sulphur (NaS), vanadium redox flow batteries (VRBs), and iron-salt flow batteries.	Compressed air or CO2 energy storage systems e.g. compressed air energy storage, liquid air energy storage.	Converts electricity into thermal energy using a heat pump and converts the thermal energy back into electricity using a heat engine.	Broad category defined by use case rather than similar technology types. Spans chemical (e.g. E-fuels, reversible fuel cells, thermochemical), electrochemical (e.g.flow, metal-air), and mechanical (e.g. compressed gas, geomechanical, liquid air) types, certain advanced thermal and pumped-heat systems.	Thermal energy produced from electricity is stored in a medium as either sensible heat or latent heat. The stored heat can then be utilised by a process for industrial use or a power cycle to generate power.
Storage capacity (MWh)	1,000	1,000	1,000	1,000	500
Discharge capacity (MW)	100	100	100	10	25
Discharge duration (hours)	~10	~10	~10	100+	~20
Technology readiness level	4-6+	4-6+	4-5	4-5	4-6+
Total plant cost ($/kWh)	224-358	118-445	236-338	26-38	20-82
Total plant cost ($/kW)	2,442-3,578	1,181-4,449	2,355-3,384	2,641-3,796	400-1,639
Footprint (MW/acre)	100-400	16-95	74-218	75-2,041	1,650-1,786
Resource lifetime (year)	25	30-35	30-60	30-40	20-30
Round-trip efficiency (RTE) (%)	65-75	57-72	57-62	50-70	95-97
Storage capacity degradation (%/year)	0.00-0.10	Assumed negligible	0.01-0.20	Assumed negligible	0.10-0.99

Established technologies	Lithium-Ion Battery (small)	Lithium-Ion Battery (large)	Pumped Storage Hydro
Capacity (MW)	10	100	838
Discharge duration (hours)	4	4	10
Over-night capital cost ($/kWh)	451	385	379

Explanatory note:

The data on novel LDES technologies were collected by the LDES Council and EPRI through industry surveys, while the data on lithium-ion batteries and PSH were provided by EPRI and the National Laboratory of the Rockies, respectively. The table above gives values for LDES projects to be contracted in 2030 (data on 2025 costs and values were requested by the LDES Council and EPRI but were insufficient across categories). Where value ranges are provided, these are the values for the LDES projects with the lowest and highest capital expenditure. Technologies were grouped into categories to maintain the anonymity of the survey respondents and their commercially sensitive data. Each LDES technology was placed in only one category. To compare technologies within a category, the LDES Council and EPRI scaled some technologies to have the same capacity and duration. To compare costs, they normalised capital, operational and maintenance costs to a common location. Costs are given as total plant cost (TPC), based on CAPEX and capturing the full system cost of the asset including power and storage sub-systems, rather than the levelised cost of storage (LCOS). LCOS divides annual costs by annual energy delivered, and is a more appropriate metric for energy storage systems that cycle frequently under well-defined operating profiles. It is not suited to LDES assets that are used less frequently but provide backup power, as it would assign a very high cost, undervaluing the economic and system benefits of LDES for system reliability.

44. LDES Council and EPRI (2025). *Cost Benchmarking for Long Duration Energy Storage Solutions.*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