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Legal Update

# Long Duration Energy Storage – opportunities, challenges and solutions

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## Introduction

Long duration energy storage ("LDES") refers to energy storage systems capable of holding and releasing energy for extended periods, typically at least eight to ten hours at full power. In practical terms, current lithium-ion battery technologies are generally considered to be unsuitable for LDES owing to their self-discharge behaviour and relatively high cost for large-scale storage. The technologies that are generally associated with LDES, therefore, comprise pumped hydro storage, compressed and liquid air storage, gravitational storage systems, flow batteries and, at the shorter end of the duration range, thermal energy storage such as molten salt.

As the world shifts its reliance away from fossil fuels towards renewables, LDES is likely to become increasingly important. A study published in 2021 by the LDES Council suggests that, by 2040, LDES will need to have scaled up to around 400 times its present-day levels to 1.5 – 2.5 TW output capacity and 85 – 140 TWh energy storage capacity globally and that 10% of all electricity generated would be stored in LDES at some point. This encompasses multiple use scenarios, with the largest proportion relating to energy time-shifting, capacity provision, and transmission and distribution optimisation in bulk power systems. In economic terms, the study estimates that this corresponds to a cumulative investment of USD 1.5 trillion to USD 3 trillion and to potential value creation of USD 1.3 trillion by 2040.

In this article, we consider the challenges faced by countries such as the UK which wish to replace reliance on natural gas for heating with renewable power and the role of LDES systems in meeting those challenges. This is, however, only one example of the challenges of balancing supply and demand. Many of the themes explored in this article will also be relevant to other countries, including strategies for incentivising investment in LDES systems.

## Challenges for de-carbonising domestic heating

**What is the challenge in switching from gas to electricity for heating?**

In a nutshell, seasonal demand variation creates a potential headache, which I discuss further below.

**How have we managed with gas heating, which millions of UK homeowners have used for decades?**

Not surprisingly, there is a large difference between summer and winter demand for gas heating. My own home used four times as much gas during the coldest three months as during the warmest three months of 2024.[1] In less well-insulated homes, the seasonal variation in consumption could be much greater.[2]

Natural gas has for decades been relatively cheap, plentiful and easy to store compressed in large volumes. Owing to its storage capacity,[3] the UK's gas supply network is able to respond to sudden and large increases in demand. According to Ofgem,[4] the current aggregate peak demand for gas for domestic heating in the UK is 300 GW, which is driven by boilers providing heat on demand, many of which will be running simultaneously at times of peak demand, such as in the early morning. Other published estimates of peak demand are significantly lower e.g., 170 GW,[5] but even this lower estimate represents a vast rate of instantaneous energy delivery, particularly when compared with the UK's total de-rated electricity generation capacity of approximately 75 GW in 2023.[6]

**What is different about using electricity for heating?**

Electricity generation and supply (and electric heating) are quite different animals to gas supply and heating. Let's assume I swap my boiler for a heat pump, for which I will assume an average

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[1] Respectively, 7,160 kWh of gas as compared with only 1,730 kWh. My total gas consumption during 2024 was 17,180 kWh. My 30 year old gas boiler is rated 75% efficient so the output energy consumed to heat my home was around 12,880 kWh, which makes it about average.

[2] Domestic UK gas consumption during the four quarters of 2020 was 122,573 GWh, 46,401 GWh, 25,924 GWh and 105,890 GWh.

[3] According to the Department for Energy Security & Net Zero as of November 2023, the UK has nine active storage facilities (30 TWh in total), together providing only one week's worth of supply at peak winter demand and the UK is a net importer of gas via interconnector pipelines and LNG cargoes. Concerns have been expressed about the UK's low levels of gas reserves as compared with storage capacities in Europe: for example, Germany has the ability to store eight times more gas than Britain.

[4] Future Insights Series: The Decarbonisation of Heat.

[5] Watson, Lomas and Buswell – *Decarbonising domestic heating: what is the peak GB demand?* Energy Policy, Volume 126, March 2019.

[6] According to the Digest of UK Energy Statistics 2024, this includes 40.5 GW of fossil fuel capacity and 25.6 GW of renewable capacity (the remainder being nuclear and other fuels).

Coefficient of Performance[7] ("COP") of 3 during the winter and a COP of 4 during the summer. A rough calculation suggests I would use around 1,800 kWh of electricity to heat my home during three winter months (averaging about 20 kWh per day) and about 325 kWh during three summer months (less than 4 kWh per day, mainly for heating hot water), with a total additional annual electricity consumption of around 3,700 kWh, almost doubling my current annual electricity consumption.

For the UK as a whole, aggregate domestic electricity consumption is a little under 100 TWh.[8] Replacing all domestic gas boilers with heat pumps would, therefore, increase that total consumption to roughly 190 TWh or by around 90%,[9] much of which would fall during the winter months, as noted above. Of course, this is only a theoretical possibility and it would take three decades to achieve that level of uptake at the Government's target installation rate of 600,000 heat pumps per year. Such a theoretical possibility also ignores the potential uptake of direct hydrogen heating using new boiler technology (on which no decision has yet been made by the Government), limited blending of hydrogen into natural gas supplies or indeed synthesising methane from green hydrogen to replace natural gas, all of which could provide alternative methods of seasonally storing energy in the form of gas reservoirs.

If a large number of UK domestic premises currently using gas were to switch to using electrical heating, one can immediately see that large and sustained seasonal peaks in electrical power demand would arise,[10] and that demand might not necessarily be spread evenly throughout the day.

In considering the likely peak consumption of electricity, one cannot, however, simply convert the peak gas consumption to the equivalent electrical consumption (taking into account the relative efficiency of boilers and heat pumps), because heat pumps operate in a different manner to boilers, at a lower output temperature[11] and can be assumed to be less "peaky". Conventional gas boiler firing tends to take the form of on-off bursts, albeit modern boilers have the ability to modulate their burners to some extent, while heat pumps operate for longer, lower-level periods to maintain a steady temperature. In practice, therefore, instantaneous demand for electrical heating can generally be expected to be lower, and there should be a natural time averaging of demand to some extent.

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[7] A ratio of heat power output to electrical power input. A value of three means the heat output is three times the electrical energy consumed by the heat pump, i.e., it is 300% efficient.

[8] Statista.

[9] According to the Office for National Statistics, around 320,000 GWh (320 TWh) of natural gas is used per annum for domestic heating. Assuming an average boiler efficiency of 80% suggests total UK domestic heat demand of about 250 TWh per annum – or about 20 million homes with an average domestic heating demand of roughly 12,000 kWh per annum. 250 TWh of heat output equates to 83 TWh of electricity input, assuming an average COP of 3.

[10] My research suggests that most UK homes can be heated by heat pumps rated between 4 and 12 kW output. If an average of 6 kW output is assumed, this would equate to around 2 kW of electricity demand per household during colder weather (when the COP might be 3 or lower). Simplistically, 2 kW x 20 million homes would represent a theoretical peak power demand of 40 GW, but only if all heat pumps were operated simultaneously, which is unlikely to apply in practice.

[11] Domestic boilers tend to have a flow temperature of 60 - 80°C whereas heat pumps operate at 35 - 55°C. Implicit in this is a lower rate of energy delivery for heat pumps and lower power consumption.

If local demand-side energy storage systems were used to time-shift demand, the instantaneous demand could be reduced further. In particular, heat pump systems can be coupled with thermal storage systems (using "phase change materials", some of which can store four times as much heat energy as water for a given volume) which can be heated up at night when demand for power is lower and utilised during the day to output heat energy. Such thermal storage systems are effectively 100% efficient given that all thermal energy that is stored finds its way out directly or indirectly into the premises in which they are installed.

Another option for shifting demand would be battery storage systems, albeit these would be less efficient than thermal systems, but which offer clear benefits where solar panels are installed. Demand-based pricing might be used to incentivise consumers to utilise such storage systems, charging them at nighttime when electricity prices are lower.

Increasing home insulation levels and using energy recovery systems (heat exchangers) in ventilation and waste water could further reduce demand by improving the energy efficiency of homes. Finally, uptake of solar panel installations, particularly when coupled with battery storage, could significantly reduce electrical demand.

Nevertheless, even if short-term peaks in demand could be smoothed out, the overall increase in demand during winter would be appreciable.[12] This seasonal peak in itself could create challenges.

### Why is high seasonal peak in electricity consumption a problem?

A seasonal peak in demand could cause a number of potential practical difficulties:

- In 2022, the UK's transmission network capacity was 68.5 GW and the distribution network capacity was only 35.9 GW.[13] Upgrades in network capacity might be required to support a switch from gas to electric heating, depending on the extent to which demand can be managed and smoothed over time.

- Total transmission losses in 2017 were 6,500 GWh and distribution losses 19,100 GWh. Most of the losses occur in distribution transformers and lines. Around 19% of total losses occur in distribution transformers and 28% arise in the local low voltage ("LV") distribution cables and overhead lines that serve domestic and smaller commercial premises. As such, introducing large peaks in domestic electricity demand could disproportionately increase such distribution losses.

- The UK's total de-rated electrical generation capacity during 2023 was approximately 75 GW (of which 25.6 GW was from renewable sources).[14] This figure, however, does not take into account

[12] As an arbitrary reference, my home used 160 kWh of gas on the coldest day of 2024, which would equate to about 40 kWh of electricity using a heat pump at a COP of 3. Extrapolating across 20 million homes gives a figure of 800 GWh (0.8 TWh), or approximately 1% of the total annual consumption on a single day.

[13] Statista Research.

[14] Digest of UK Energy Statistics 2024.

transmission and distribution and losses. Peak demand reached 58 GW during 2023.[15] Current generation capacity, even when supplemented by imports of electricity via interconnectors, might be insufficient to meet the peaks in demand that would arise from widespread adoption of heat pumps, particularly after allowing for network losses, but again, the severity of the challenge may depend on the extent to which demand can be managed and smoothed.

There will, of course, be other significant factors that increase overall demand, including the uptake of electric vehicles, decarbonisation of industry and growth in data centres, but without contributing to the same extent to seasonal peaks in demand.

### Why can't we simply increase generation capacity to meet peak demand?

Increasing generation capacity on its own to meet peak demand is unlikely to be a practical answer. Given the broad duration peak in winter heating demand, it might not make economic sense to increase generation capacity to meet the maximum projected winter electrical power demand for the coldest winter. The full additional generation capacity might only be fully used for short periods and would be underutilised for much of the year.

Moreover, renewable power is also inherently intermittent. Wind power is naturally variable and it may be difficult to predict generation capacity (winter "wind droughts" occur every few years); photovoltaic power generation is absent during the night and has reduced capacity during the shorter and darker winter days as compared with the summer, which is the inverse of seasonal demand for heating. These factors are taken into account by "de-rating" assumed renewable generation capacity, but there is another side to the renewables coin: renewable power generation may, during periods of high output, result in generation capacity significantly exceeding demand, i.e., excess capacity may exist at times when it is not directly needed.

A further factor which complicates the equation of how demand can be met is the existence of interconnectors which allow importation of power from Europe and Ireland to supplement generation capacity (and the export of excess capacity). The current total interconnector capacity is approximately 10 GW. The UK imported 33 TWh of electricity and exported 10 TWh during 2023.[16] Economics might dictate greater reliance on interconnectors rather than generation, at the expense of reduced energy security.

## Long duration energy storage – a solution?

### What is the solution?

Aside from reducing energy demand through better insulation of homes[17] and managing and smoothing short-term peaks in demand via local short-duration energy storage (e.g., distributed

[15] NESO Clean Power 2030 (Annex 1: electricity demand and supply analysis), December 2024.

[16] ibid.

[17] Heat pumps may be unsuitable for poorly insulated homes as their heat output may be insufficient to keep up with heat losses.

battery energy storage systems), one answer is to store excess energy generated during periods of low demand and to use that stored energy during periods of high demand. The effect of this would be to time-shift energy generation so that the load is evened out over time. The storage must necessarily be of high capacity and long duration, potentially subsisting over many weeks or even months.

### What quantity of storage capacity might be required?

Determining the appropriate capacity of LDES involves numerous variables and would be a highly complex exercise. On a basic level, the amount of storage required depends on making assumptions about future electricity demand (noting that decarbonisation will likely result in a general increase in demand[18]) and generation capacity, including both dispatchable and non-dispatchable sources, as well as the extent to which the UK may rely on interconnectors to import electricity to meet periods of excess demand.

A further uncertainty is the extent to which gas to power might continue to be utilised to meet peak demand, potentially coupled with carbon capture and storage. It also seems possible that heating networks using heat derived from nuclear and thermal power stations and other sources (e.g., large-scale disused mine heat extraction) might supplement the supply of domestic heat energy. I am not, therefore, going to attempt to guess the capacity of LDES that may be required in the future, but merely observe that it will be appreciable.

A mixture of LDES and distributed short duration thermal and battery energy storage might offer an optimised solution in combination. The reason for this is that short duration energy storage systems offer a way to spread demand over a period of hours (time-shifting intra-day), alleviating daily peaks in power demand. Not only could this reduce the peak power load on generators but it could also potentially alleviate bottlenecks in distribution networks. As noted above, thermal energy storage can be directly coupled to heat pumps and offers an efficient solution to reduce intra-day peaks in demand.

### NESO's Action Plan for LDES to 2030

| Pathway to net zero | Description and assumptions | Annual electricity demand (TWh) | Peak electricity demand (GW) | Total installed generation capacity (GW)[19] | Energy storage output (GW)[20] | Energy storage capacity (GWh)[21] |
|---|---|---|---|---|---|---|
| | 2024 values for comparison | 290 | 58 | 125 | 10 | 63 |

[18] There are numerous factors at play here, including electrification of road vehicles and the production of green hydrogen for decarbonising industrial processes.

[19] Includes all generation, interconnector and storage capacity as well as electric vehicle-to-grid ("V2G") capacity available at winter peak.

[20] Includes V2G capacity available at winter peak.

[21] Excludes V2G storage capacity.

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|---|---|---|---|---|---|---|
| "Holistic Transition" | A mix of electrification and hydrogen, with hydrogen mainly used around industrial clusters. Hydrogen is not used for heat except as a secondary fuel for heat networks in small quantities. Consumer engagement is very strong through adoption of energy efficiency improvements and demand shifting, with smart homes and electric vehicles providing flexibility. A high-renewable capacity pathway, with unabated gas dropping sharply. Moderate levels of nuclear capacity and lowest levels of hydrogen dispatchable power. Supply side flexibility is high, delivered through electricity storage and interconnectors. No unabated gas remains in 2050. | 705 | 120 | 439 | 96 | 285 |
| "Electric Engagement" | Net zero is met mainly through electrified demand. Consumers are highly engaged in the transition through smart technologies that reduce energy demand, such as electric heat pumps and electric vehicles. Pathway with the highest peak electricity demand, requiring high nuclear and renewable capacities. Also has the highest level of bioenergy with carbon capture and storage across all net zero pathways. Supply side flexibility is high, delivered through electricity storage, interconnectors and low carbon dispatchable power. | 785 | 144 | 450 | 81 | 295 |
| "Hydrogen Evolution" | Net zero is met through fast progress for hydrogen in industry and heat. Widespread access to a national hydrogen network is assumed. Some consumers will have hydrogen boilers, although most heat is electrified. There are low levels of consumer engagement within this pathway. Hydrogen is used for some heavy goods vehicles, but electric vehicle uptake is strong. Pathway sees high levels of hydrogen dispatchable power plants, leading to reduced need for renewable and | 797 | 122 | 384 | 56 | 230 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | nuclear capacities. Hydrogen storage provides the most flexibility in this pathway. | | | | | |

It is interesting to note that the projected annual demand values for all three scenarios are considerably greater than the prediction of 500 TWh in the 2030 Action Plan, as well as a similar estimate in the Royal Society's 2023 study.

The projected differences in energy storage capacity under each pathway reflect the extent to which hydrogen and related infrastructure is adopted. Only the Hydrogen Evolution scenario anticipates significant adoption of hydrogen for domestic heating, i.e., using hydrogen-fuelled boilers (69 TWh annual demand).

### LDES technologies

In the following paragraphs, I consider briefly the current technologies available for LDES, focusing primarily on batteries, pumped hydroelectric storage, compressed and liquid air energy storage and compressed hydrogen storage.

### Conventional battery storage (Li-ion)

Despite a substantial fall in the price of cells over the past 10 years, conventional battery storage using lithium ion ("Li-ion") technology is relatively expensive as compared with other bulk storage technologies, and all the more so when implemented at large scales. Total project costs for Li-ion battery storage range between USD 393 and USD 581 per installed kWh of capacity, as compared with USD 106 to USD 200 for pumped hydro, according to World Bank figures.

Li-ion cells are not well-suited to long duration storage applications: they have a limited lifespan, depending on the number of charge and discharge cycles, and batteries also self-discharge slowly over time and the health of Li-ion batteries may be adversely affected if storage temperatures are not carefully controlled. Nevertheless, the Government's LDES Technical Decision on the cap and floor regime (see below) does not exclude Li-ion batteries.

### Flow batteries

A flow battery stores energy in two liquid electrolytes (one positive and one negative) in separate tanks, which are circulated across two electrodes, separated by a porous membrane, to generate power. Unlike traditional batteries that store energy in solid electrodes, flow batteries offer greater flexibility in scaling power and energy capacity (which can be separately adjusted, unlike solid electrolyte cells), making them suitable for large-scale energy storage. Round-trip efficiency is 65 - 80%.

The most widely used chemistry is based on vanadium in different oxidation states on the two sides, but this creates a practical problem as vanadium is in short supply and is expensive. Alternative chemistries are being developed but are not yet commercialised.

### Iron-air batteries

Iron-air batteries are mentioned in the 2030 Action Plan as a possible option for LDES. This battery chemistry uses iron as the anode and atmospheric oxygen as the cathode and involves the oxidation of iron during the discharge cycle and its reduction during charging, a process that is both reversible and capable of storing a large amount of energy. Their attractiveness lies in their ability to use abundant and non-toxic materials, presenting a sustainable and cost-effective alternative to Li-ion cells.

The technology is, however, not yet commercialised and technical challenges hinder their widespread adoption. Scaling up production to meet global demand remains a significant hurdle, along with improving durability and cycle life, which remain the focus of research and development efforts.

### Pumped hydro

Pumped hydro storage uses electricity to pump water from a low to a high level reservoir. The stored water is released through turbines to generate electricity, converting its gravitational potential energy into electrical energy. Pumped hydro is a mature technology with a long history of worldwide deployment. Its round-trip efficiency is 78 - 81%.

There are currently four pumped storage hydro facilities, located in Scotland and Wales and commissioned between 1963 and 1984, with a combined storage capacity of 26.7 GWh and an output capacity of 2.8 GW, representing less than ten hours' worth of energy storage at full output power. Six new schemes are planned in Scotland, with a total output capacity of 3.9 GW and storage capacity of 95.8 GWh. If all were constructed, they would increase the UK's pumped hydro storage capacity to 122.1 GWh.

### Green hydrogen

In the case of hydrogen, a large portion of electrical energy is lost in electrolysis, treatment and compression of the gas and re-conversion to electricity (using fuel cells or combined cycle gas turbines):

- The efficiency of polymer electrolyte membrane ("PEM") electrolysis is expected to reach 82 to 86% by 2030.
- To compress hydrogen to 200 bar pressure consumes 10% of the energy stored, and at 800 bar consumes 15.5%.

- A combined-cycle gas turbine power plant has a best case re-conversion efficiency of around 60%. A simple-cycle gas turbine, which is more likely to be utilised in this context, has a lower efficiency of 35% to 40%.

This gives a round-trip efficiency of well under 50% for storage at 200 bar, which is much lower than pumped hydro storage. The Royal Society quotes a round-trip efficiency of only 41% (based on re-conversion using a fuel cell or 4-stroke engine), at which, for a given net energy output, 2.4 times the input electrical energy would be required. A higher round-trip efficiency might be achievable using a combined-cycle turbine generator, but it is still likely to remain below 50%, and combined cycle systems may not be practical for peaking power plants as they are more suitable for baseload generation given that they take an appreciable period of time to reach full efficiency.

The energy density of hydrogen by mass is 33.3 MWh per tonne. At 40% re-conversion efficiency using a simple-cycle power plant, to store 100 TWh of net energy output would require approximately 7,500,000 tonnes of hydrogen gas. If stored at 200 bar pressure and 20°C temperature, at a density of 15 kg/$m^3$, 7,500,000 tonnes would occupy a volume of 500 million $m^3$ (equivalent to 200,000 Olympic-size swimming pools).

Whilst this seems like a large storage volume, it is a small fraction of known theoretical storage resources in underground salt caverns in the UK, being the only proven technology for storing large volumes of pure hydrogen. One recent study estimated that there might be up to 2,150 TWh of theoretical hydrogen storage capacity in salt caverns in the UK, although subsequent analysis has suggested only 10% of this might be usable. Nevertheless, East Yorkshire alone has more than enough capacity to store 100 TWh of hydrogen.

Britain currently has underground cavern storage capacity for about 25 GWh of hydrogen and over 20 TWh of natural gas. A cluster of three 70,000 $m^3$ caverns used to store hydrogen on Teesside has been in operation since 1972.

A variation on green hydrogen is green ammonia, which can be stored as a liquid at relatively low pressure and has a volumetric energy density higher than liquid hydrogen and about half that of methane. Current production technology (primarily the Haber-Bosch process) is, however, not well suited to intermittent production and alternative technologies such as a catalytic electrochemical process remain inefficient and have not been commercialised. Direct synthesis remains subject to research and development and if commercially successful would be a game-changer.

### Compressed air energy storage

Compressed air energy storage (“CAES”), whilst less efficient than compressed hydrogen in volumetric energy density terms, is also under serious consideration as a LDES solution. Air is compressed using excess electrical energy and the compressed air can be run through a turbine generator to recover a portion of that energy. CAES has a round-trip efficiency of up to 56%, which is more efficient than compressed hydrogen storage.

A British Geological Survey[22] study identified 3,880 caverns suitable for compressed air energy storage with an estimated total volume of 1,830 million $m^3$ (1.83 $km^3$). It estimated that a CAES plant with a full charge of 10 caverns could store 25.32 GWh of energy, which could be converted to 23.19 GWh of work, requiring 43.27 GWh of energy to produce, reflecting the 54% round-trip efficiency. The Cheshire Basin could potentially support around 100 such CAES plants, giving a potential total exergy storage capacity of 2.53 TWh and a power output of 40 TW.

To mitigate the burden on the national grid, one could expect storage sites to be distributed around the UK to some extent, noting that there are large halite deposits in the Cheshire, East Yorkshire and Wessex basins. Some of these sites are already used for the storage of natural gas.

### Liquid air energy storage

Liquid air energy storage ("LAES") involves using electricity to cool air (through compression and expansion) until it is liquid at atmospheric pressure and storing it in a well-insulated container, whereby it can be maintained cryogenically as a liquid for extended periods (potentially many months) with minimal losses, typically below 0.05% per day. To utilise the stored energy, the liquid air is heated, evaporated, expanded and run through a turbine generator. The initial compression and liquefaction process produces heat which in principle can be stored to be used in the evaporation process.

LAES offers a relatively high round-trip efficiency of 55 – 65% and is unconstrained by geological locations (which affect siting of CAES and pumped hydro). At least one commercial-scale LAES facility is already operating in the UK and further facilities are planned.

### Gravitational energy storage

Electricity can be used to raise large masses, increasing their potential energy. That energy is recovered over the discharge cycle as the masses are lowered, driving generators to create electricity. This technology is currently not deployed at large scale and remains under development.

### Thermal storage

Thermal storage systems are worth a mention, whereby high grade heat energy is stored in molten salts, solids, thermal oils, liquid metals or as steam or lower grade heat is stored in water or other materials. These systems really come into their own where district heating networks exist.

For example, water pit storage is deployed to provide district heating in Austria, Denmark and Germany. With a temperature range of 70°C, water can store 82 kWh/$m^3$ of thermal energy, with losses below 0.1%/day in large systems and achieving heat out/in efficiencies of over 90% for heat stored in late summer and delivered in winter.

[22] Parkes, D.; Evans, D.J.; Williamson, P.; Williams, J.D.O. Estimating available salt volume for potential CAES development: A case study using the Northwich Halite of the Cheshire Basin. J. Energy Storage 2018, 18, 50–61.

Molten salts store heat in the range of 300 – 580°C and are currently used in concentrated solar power plants and could be used in conjunction with nuclear power plants to buffer output and render nuclear flexible.

Carnot batteries use resistive electrical heating to heat up and store heat at high temperature in solid materials such as concrete for later delivery as electrical power generated by a steam turbine. The Royal Society's study suggests, however, that whilst Carnot batteries are expected to be one of the cheapest large scale storage options, they will be more expensive than hydrogen storage without being much more efficient.

## Duration of storage and efficiency

Storage systems with large capital costs per unit of energy stored have to be cycled frequently in order to recover the investment. Storage technologies can, therefore, be grouped into categories according to the typical time in which their contents must be cycled:

- category 1: minutes to hours: conventional (non-flow) batteries;
- category 2: days to weeks: flow batteries, advanced compressed air energy storage, Carnot batteries, pumped thermal storage, pumped hydro, liquid air energy storage; and
- category 3: months or years: synthetic fuels, ammonia, hydrogen.

Conversely, efficiency and relative cost decreases from category 1 to category 3.

The Royal Society's study[23] concludes that a combination of advanced compressed air energy storage ("ACAES") and hydrogen storage provides the benefits of the greater efficiency of the former and the relatively lower storage cost of the latter. While the study notes that the costs and efficiencies of large ACAES systems are poorly known, for a wide range of assumptions it found that combining ACAES with hydrogen would be likely to lower the cost relative to that found with hydrogen alone (by up to 5%, or possibly more), although not assured. When they are optimally combined, the capacity of ACAES is much smaller than that of hydrogen storage, but ACAES delivers more energy because it is cycled more frequently.

## Addressing concerns for investors in and lenders to LDES projects

### Risks and revenue uncertainty

One might take the view that an LDES project offers an inherent arbitrage opportunity to buy excess electricity when it is cheap and sell it at a higher price when it is in high demand, creating a natural profit generation device. This is, however, overly-simplistic and ignores multiple risks and uncertainties, not the least competition from other LDES projects and the risk of over-supply of energy storage, changes in demand for electricity (which might be lower than expected), competition

[23] *Large-scale electricity storage*, September 2023.

from interconnectors and assumptions about generation capacity being incorrect. As such, long build times combined with revenue uncertainty have inhibited investment in LDES development over the last 40 years.

### Cap and floor support scheme

Developers have, therefore, been lobbying for project revenue support and, in October 2024, following a consultation process, the Government announced a decision to introduce a *cap and floor* investment support scheme with Ofgem acting as regulator and investment support scheme delivery body.[24] The scheme is expected to be similar to the cap and floor regime that supports interconnector projects, utilising a proven model that has successfully facilitated investment and is familiar to the market. Its objective would be to ensure investors receive a minimum amount or "floor" revenue to enable their investment in LDES assets, whilst the "cap" would provide returns to consumers for their support where LDES assets generate revenue above the cap.

In March 2025, the Department for Energy Security & Net Zero and Ofgem published a Technical Decision Document to confirm key details, in particular that:

- the cap will be set to allow recovery of invested capital (debt and equity) and to provide a fair return on investment if the assets perform well in the market; and
- the floor will be set to allow recovery of invested capital (debt and equity) along with a rate of return that is comparable to the cost of debt.

The Government and Ofgem stated that they believe this sets the right balance of incentivising investment and encouraging appropriate operation of LDES assets, whilst avoiding unnecessary risk to consumers. Their initial position is also that LDES assets should be subject to the cap and floor regime for 25 years and that all capital costs would be recovered over this period. Ofgem may consider requests for different regime lengths, but any request for a shorter duration must be at least 20 years, because shorter durations are likely to result in higher floor levels, increasing potential consumer support in any year, as costs would be spread over a shorter period. LDES developers will be able to recover all economic and efficient capital and operational costs as long as they comply with their licence obligations (and subject to any incentive mechanisms which may reduce their recovery).

The cap is proposed to be flexible (a "soft" cap), meaning that if revenues exceed the cap, the extra revenue is shared between the licensee and the consumer. The exact details of how this sharing will work will be determined after further consultation.

The floor would allow recovery of invested capital (debt and equity) and provide a return similar to the cost of debt for both equity and debt investors. Developers will be given a choice between allowing Ofgem to set the floor administratively (i.e., it makes a determination) or to undertake a

[24] Long duration electricity storage consultation: Government Response (Department for Energy Security & Net Zero), October 2024.

competitive debt-raising process under an optional “project finance” variation. The floor set through this approach will be designed to meet debt obligations.

To be eligible for support, LDES projects must have a minimum capacity of 100 MW (Stream 1, being currently limited to pumped hydro storage and Li-ion batteries) or 50 MW (Stream 2, comprising other technologies and likely to encompass flow batteries, LAES and CAES), must be able to output that amount of power continuously for eight hours and must be able to maintain this level of performance over the duration of the support period.

Note that the cap and floor scheme does not apply to hydrogen-based energy storage or generation projects. Separate business models are proposed for these technologies, as briefly discussed below.

NESO will provide advice on the range of LDES capacity that Ofgem should seek to provide cap and floor schemes in the first allocation round, and support Ofgem in assessing projects that apply for support through the scheme. Meanwhile, in the second and third quarters of 2025, Ofgem is expected to decide, via public consultation, whether to use an administrative cap or a competitive cap, and how the proposed “soft” cap would work alongside either a competitive or administrative process.

### Sources of revenue for LDES projects

LDES projects should, in principle, be able to generate three primary sources of revenues:

- *electricity price arbitrage*, namely buying electricity when the price is low and selling stored electricity when prices are higher (taking into account the round-trip efficiency);
- participation in the *capacity market* (“CM”), whereby power generators compete for contracts at auction with a duration of 1 to 15 years under which they are paid a charge for their availability to provide capacity and to deliver energy at times of peak demand, a mechanism which is intended to ensure that there is a reliable and secure generation capacity available to meet demand and to address the intermittency and unpredictability of variable renewable power generation and periods when the system is stressed, e.g., by cold snaps; and
- provision of *ancillary services* (“AS”), including the Balancing Mechanism (“BM”),[25] redispatch and grid congestion management, voltage support, frequency response/stabilisation, reserve services and black start capability.

Note that different LDES technologies have different response times and not all technologies are suitable to provide ancillary services that require instantaneous response, such as Fast Frequency Response (“FFR”).

[25] A real-time market where the Electricity System Operator (“ESO”) manages the electricity supply and demand balance on the British power grid.

Many respondents to the Government's consultation on LDES in 2024 suggested that beneficiaries of the cap and floor scheme should be allowed to participate in other electricity markets such as CM, as well as participating in the BM and earning revenue from other ancillary services, potentially allowing "revenue stacking". Many argued that such wider participation would facilitate maximisation of revenues and diversification of revenue streams, reducing the risk of revenues dropping below the floor and then accordingly minimizing the potential cost to consumers.

A number of respondents highlighted that the electricity interconnectors scheme allows recipients to participate in the CM while receiving cap and floor support. Some, however, recommended that LDES projects only be allowed fettered access, such as only being permitted to compete for one-year contracts, and to be required to be a price taker (whereby capacity providers cannot exit the auction until the price drops below the price-taker threshold).

A small number of respondents disagreed with allowing LDES assets to participate in the CM as it could cause distortions to the auction prices, as they might be able to submit lower prices than other assets due to the support provided by the cap and floor. Some respondents felt that recipients of the cap and floor scheme should only be able to access the balancing mechanism and ancillary services markets.

In its response to the consultation published in October 2024, the Government has confirmed that it intends to allow access to the CM, subject to considering what parameters around such participation should apply.

## Hydrogen production, storage and power generation

A discussion of hydrogen-based energy systems is complicated because clean hydrogen production in the UK is expected to be developed at scale initially based predominantly on blue hydrogen (derived from natural gas through steam reforming, coupled with capture and storage of the carbon dioxide produced as a by-product) with green hydrogen production (through electrolysis) being an alternative parallel or future expansion pathway. Clean hydrogen infrastructure development is also expected to comprise multiple use cases, including potentially blending into natural gas for heating (but only as a last resort where a producer has insufficient customer load), industrial consumption and transportation applications, as well as hydrogen to power ("H2P").

Hydrogen technologies cannot, therefore, be considered in the same manner as LDES in the UK and represent a more complex and special case.

The Government has proposed a series of "business models" to support the development of hydrogen production, storage, transportation and hydrogen to power, as well as carbon capture utilisation and storage ("CCUS") projects including both transportation and subterranean storage of $CO_2$ (which are expected to be based on a Regulated Asset Base model) and CCUS-abated gas to power projects.

### Hydrogen production business model

The Government has proposed a hydrogen production "business model" which will provide revenue support to hydrogen producers to overcome the operating cost gap between low carbon hydrogen and high carbon fuels, being designed to incentivise investment in low carbon hydrogen production and use. This will be implemented through a "Low Carbon Hydrogen Agreement" which includes elements which are similar to the contracts for difference ("CfD") regime applicable to low carbon electricity and the dispatchable power agreement ("DPA") methodology applicable to CCUS-abated gas to power projects, with the intention of providing price certainty to the hydrogen producer.

### Hydrogen transport and storage business models

In the British Energy Security Strategy, the Government committed to designing, by 2025, new business models to stimulate investment in hydrogen transport and storage infrastructure, which it considered essential to grow the hydrogen economy. These business models are expected to mitigate demand risk through external subsidy by providing revenue support under a contract between the infrastructure provider and a Government-appointed counterparty, establishing a minimum (probably annual) revenue "floor", irrespective of the extent to which a facility is used. A revenue "cap" or "gainsharing" arrangement might also apply.

Alongside revenue support contracts, the Government also considers that the hydrogen transport business model might also incorporate a Regulated Asset Base ("RAB") approach to facilitate and support the financing of hydrogen pipeline projects.

### Proposed Hydrogen to Power ("H2P") business model

NESO considers lower carbon dispatchable technologies such as H2P to be important for achieving a clean power system, reducing reliance on weather-dependent renewables and over the long-term replacing the need for unabated gas power generation. NESO has estimated that the GB electricity system could need around 40 – 45 GW of long duration flexible capacity by 2030.

Between December 2023 and February 2024, the Government ran a consultation on the need for, and potential design of, a market intervention to support the deployment of H2P projects. External analysis, published alongside the consultation, indicated that while some H2P plants in specific circumstances with relatively easy access to low carbon hydrogen fuel could come forward, market conditions meant that a full range of H2P plants would struggle to be deployed. Two key inter-linked barriers were identified, namely uncertainty and increased investment risk from H2P being a new technology and dependence on nascent critical enabling infrastructure, i.e., hydrogen production, transport, and storage creating 'cross-chain risks', and hydrogen fuel supply risks.

In its consultation response document published in 2024, the Government committed to introduce a "business model" to support deployment of H2P projects (the "H2P BM"). The H2P BM is expected to be based on elements of the CCUS-abated gas to power DPA-style business model, adapted to suit the needs of H2P. During 2025, the Government plans to present more detail on the proposed design of a bespoke H2P BM and to undertake a further market engagement exercise to invite feedback on those plans.

### Conclusions

It is clear that long duration energy storage systems will play a key role in facilitating decarbonization by optimising electricity generation and supply arrangements, taking into account increased reliance on renewables. The UK is already forging ahead with the expansion of LDES capacity as well as clean hydrogen infrastructure (including hydrogen storage) and has taken steps to set up support arrangements to make projects more attractive to investors and their lenders. We may expect similar incentives or alternative revenue support schemes to be adopted worldwide over the next few years.

## Contact

**Harry K. Brunt**
Partner
+44 (0) 20 7220 5720
hbrunt@hunton.com

## Related Service

Energy and Infrastructure

## Media Contact

**Lisa Franz**
Director of Public Relations

**Jeremy Heallen**
Public Relations Senior Manager
mediarelations@Hunton.com