Long Duration Electricity Storage

Response to DESNZ Request: Q1 and Q2

NESO
National Energy System Operator

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Executive Summary

Background and context

This report forms part of our response to a request from the Department for Energy Security & Net Zero (DESNZ) to provide advice to support the design of the proposed Long Duration Electricity Storage (LDES) cap and floor scheme. This advice is provided in accordance with our statutory duties set out in paragraph 171 of the Energy Act 2023.

The information included in this response is intended to support DESNZ and Ofgem in delivering the *Technical Decision Document (TDD)* for Window 1 of the scheme, which is due to be published in March 2025. Government and Ofgem have stated that Window 1 will focus on projects which can be delivered by the end 2030 or 2033. Further windows are expected to be opened over time.[1]

As previously identified by DESNZ, LDES technologies are faced with "*significant barriers to deployment under the current market framework due to their high upfront costs and a lack of forecastable revenue streams*". To help overcome these barriers and to enable investment in LDES technologies, the introduction of a new cap and floor mechanism has been proposed by the government.

Long duration electricity storage is a broad term. The government has set out that only those technologies which meet the electricity storage definition in the Energy Act 2023, as well as technical eligibility criteria (e.g. being able to discharge continually for a minimum duration of six hours), would be eligible to receive support through the scheme.[2] The types of technologies that are expected to be supported by the scheme include pumped hydro energy storage (PHES), liquid air energy storage (LAES), compressed air energy storage (CAES) and other innovative forms of storage. It is these technologies that we focus on in this report, and which we refer to as "LDES" throughout.

LDES technologies will be critically important in a clean power system. They provide a means of storing renewable electricity during periods of surplus supply for its re-deployment during periods of reduced renewables output. There is currently 2.8 GW of installed LDES capacity in Great Britain, which is comprised of four pumped hydro energy storage assets in Scotland and Wales. **Our *Clean Power 2030 advice to government* set out that LDES assets have the potential to reduce curtailment, constraints and costs while enhancing security of supply and are "*particularly important for longer term flexibility and additional operability needs.*"** Our two clean power pathways identified

[1] Call for input - LDES Cap and Floor Regime: Our Role, Plan, and response to the DESNZ publication, Ofgem (2024)
[2] Long duration electricity storage consultation: government Response, DESNZ (2024)

levels of 4.6 GW and 7.9 GW of LDES capacity to support the delivery of a clean power system by 2030.[3]

The 'Resource Adequacy in the 2030s' report[4] published by ESO in 2022, set out the benefit that storage assets of increasing duration can provide in supporting adequacy whilst simultaneously helping to address the challenge of meeting net zero. **However, it is not the expectation that these technologies alone will cover the system's needs, especially during long periods of low renewable output**. That will require technologies that can provide energy at a much larger scale for longer periods, such as unabated gas generation, power carbon capture and storage (CCS) and hydrogen to power, to ensure future critical stress events can be covered.

The request for advice

The request for advice covers three questions which are set out in detail in the next section. This report focuses on the first two of those questions:

1. *Advice from an electricity system perspective on the costs and benefits of:*
    a. *increasing the minimum duration for a qualifying LDES asset to beyond 6 hours, and what an optimal minimum duration might be.*
    b. *lowering the minimum capacity required for eligibility for Stream 2 projects,*

2. *The full range of benefits and costs of LDES for the electricity system which Ofgem should be taken into account when assessing project cap and floor applications.*

Approach

Further details on the approach are set out in the main report.

To answer question 1a and 1b, we drew on the expertise and experience of subject matter experts (SMEs) across NESO to determine the possible system impacts of making the proposed changes across a range of relevant "system aspects," including security of supply and thermal constraints. In most cases it has been more appropriate to answer the question through a qualitative assessment, except for the thermal constraints costs where we conducted analysis using the PLEXOS model. Given the limitations of modelling the changes proposed in question 1a and 1b, which are set out in more detail in the main report, we have not assessed system monetary "costs", but instead a more general view of advantages, disadvantages and risks.

Questions 1a and 1b specified that we should consider the "electricity system" costs and benefits. However, it is important to note, as DESNZ stated in their request, that "the majority of LDES capacity at least in the medium term (to 2035) is likely to be in the form of Pumped Hydro Energy Storage (PHES)." Analysis of the PHES projects that are visible to

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[3] Clean power by 2030: Advice to government (NESO, 2024)
[4] Resource adequacy in the 2030s [2022, Published as NG-ESO with AFRY]

NESO with confirmed connections indicates that at least 98% of the capacity will be connected to the transmission network. Our focus is consequently on the transmission system. Where appropriate and relevant, we have made a high-level assessment of the distribution level impacts, although further work and engagement with Distribution Network Operators (DNOs) may be needed to provide a more detailed picture of any potential impacts at this level.

To answer question 2, we drew on NESO's existing experience with assessing projects for the interconnector cap and floor regime.

Summary of key findings

Our findings in relation to question 1 are summarised in Figures 1 and 2. We have highlighted where there are possible material system impacts at a transmission or distribution level across each of the "system aspects" at the transmission (labelled Tx in the tables) and distribution (labelled Dx in the tables). A material impact for these purposes is defined as an impact which could result in one or both of the following:

a) Government, Ofgem, transmission owners, distribution network operators, NESO needing to do something different (e.g. system change, policy change, process change) to accommodate the change, beyond what is already planned for.
b) One or more potential impacts in the energy market, which might result in a noticeably different outcomes across energy trilemma objectives (e.g. increased costs to consumers, delays to decarbonisation, increased probability loss of load).

We made an important **cross-cutting assumption that the policy changes proposed in questions 1a and 1b would not alter the overall total capacity of LDES** that DESNZ and Ofgem would seek to procure through Window 1.

We identified some potential material impacts of excluding projects which are currently configured as 6 hours units and if projects reconfigure to meet the higher duration threshold (question 1a). The exact nature of these impacts will depend on how developers respond to any increase in the proposed minimum duration threshold. These impacts could be identified through individual assessments, considering their location, total capacity and energy and technology type. It has not been possible to identify an "optimal" minimum duration for capacity to be supported through the scheme. Our capacity adequacy assessment, published in 2022, identifies that there is a benefit to LDES with 6 hours duration and above. Individual scheme assessments could give a more accurate view of the benefits of different projects.

We did not identify any material system impacts (e.g. advantages or disadvantages) from reducing the minimum capacity threshold for Stream 2 (question 1b). As set out above, our analysis focused on the transmission system (as we assume most LDES assets will connect there). We considered that the impacts at distribution level would be similar, although further analysis and engagement with DNOs may be needed. Enabling greater geographical dispersion of LDES assets could help alleviate local network constraints and weaknesses and possibly also provide ancillary services in areas that need them.

However, at the scale of these assets this is not deemed to be material. Furthermore, there are currently no clear incentives for assets to locate in specific locations. Future changes, such as the Strategic Spatial Energy Plan (SSEP), Regional Energy Strategic Plans (RESPs) and potential shifts to a locational market may have some baring but the nature of the impact is likely to vary from asset to asset. Benefit at a system level is partly reliant on these assets taking part in the Balancing Mechanism (BM). We expect most would take part from a revenue perspective and even if not, there can still be benefits to the system through participation in the wider market at a distribution level.

Our response to question 2 was based on our expertise and experience of conducting assessments as a part of the interconnector cap and floor regime. The suggested cost and benefit considerations are set out in the main report.

Figure 1: LDES Q1a – System impacts of raising the minimum duration across both streams (currently 6 hours)

General assumption: The change in duration threshold **does not impact on the overall capacity of LDES that is procured** via the cap and floor scheme.

	System aspects				
Assumed impacts	**Security of supply**	**Operability**	**Thermal constraints**	**Connections**	**Costs and emissions**
Projects below 7-8 hours in duration cannot receive support from the cap and floor scheme.	[Ql] **Unlikely to be a material impact on Tx or Dx system**. Overall capacity and energy are more important but **6-hour projects can still useful to security of supply**.	[Ql] **Unlikely to be a material impact on Tx or Dx system**. Longer duration assets could support the wider system but will remain operable regardless of decision.	[Ql/Qn] **Possible material impact at Tx or Dx system level.** A small benefit to moving to 8-hour duration indicated by modelling – but highly dependent on location.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Duration of an asset does not impact on the connection.	[Ql] **Possible material impact on Tx or Dx system.** Individual assets of lower than 7-8 hours may have cost and/or emissions benefits which could be determined by assessment.
Fewer projects enter the cap and floor scheme and therefore fewer are available in the market.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Overall capacity and energy are more important than total number of projects.	[Ql] **Unlikely to be a material impact at Tx and Dx level**. Overall capacity and energy are more important than number of projects.	[Ql/Qn] **Possible material impact at Tx or Dx system level**. Project benefit will be locationally dependent for impacting on constraints – potentially excluded projects may be in locations of interest.	[Ql] **Unlikely to be a material impact at Tx and Dx level**. The number of projects impacts on the number of connections. But not expected to change the overall connection queue picture.	[Ql] **Possible material impact on Tx or Dx system.** Individual assets of lower than 7-8 hours may have cost and/or emissions benefits which could be determined by assessment.
A **smaller range of LDES technologies** can take part in the cap and floor scheme - however most innovative technologies are 8+ hours.	[Ql] **Unlikely to be a material impact at Tx and Dx level**. Overall capacity and energy are more important but greater diversity of assets is helpful to security of supply.	[Ql] **Unlikely to be a material impact at Tx and Dx level**. There may be benefits of having more diversity of assets to supply a range of services across the system.	[Ql] **Unlikely to be a material impact at Tx and Dx level** But if innovative LDES are excluded it may make areas where PHS is not viable more reliant on other forms of long duration flex.	[Ql] **Unlikely to be a material impact at Tx and Dx level**. Would not anticipate this to impact on connections.	[Ql] **Possible material impact on Tx or Dx system.** Individual assets of lower than 7-8 hours may have cost and/or emissions benefits which could be determined by assessment.
Some projects may reconfigure to reduce their capacity to increase their duration	[Ql] **Possible material impact at Tx or Dx level –** depending on how units are reconfigured. **Impact of reducing capacity may be offset by increasing duration.**	[Ql] **Possible material impact at Tx or Dx system –** depending on how units are reconfigured. **Impact of reducing capacity may be offset by increasing duration.**	[Ql] **Possible material impact at Tx or Dx system level –** depending on how units are re-configured. Location is more important fact for constraints.	[Ql] **Unlikely to be a material impact on Tx or Dx system** Could impact on existing connections agreements if projects look to reduce MW capacity – but this is a matter for developers.	[Ql] **Possible material impact on Tx or Dx system**. Impact on costs dependent on changes proposed and whether or not such changes the £/MW or £/GWh costs.

Figure 2: Q1b – System impacts of reducing the minimum capacity for Stream 2 to below 50MW

General assumption: The change **does not impact on the overall capacity of LDES** that is procured via the cap and floor scheme.

	System aspects				
Assumed impacts	**Security of supply**	**Operability**	**Thermal constraint costs**	**Connections**	**Costs and emissions**
Smaller capacity projects, below 50MW, will be supported through the cap and floor scheme (and will therefore be available in the electricity market).	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Overall quantum is more important than size of units. Smaller units can have lower visibility at Tx level. Work underway to address this.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** At Tx level there is currently lower visibility and controllability of Dx-assets but NESO work underway to overcome this (e.g. DER Programme).	[Ql/Qn] **No material impact at Tx or Dx system level.** Asset location is more important for constraints.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Overall quantum and number of connections is more important – however for Window 1 we expect a low volume of connections.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Negligible impact on overall costs and emissions of the wider system due to small size of assets.
A larger number of smaller projects will receive support through the cap and floor scheme and be available in the market.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** As above, overall quantum of LDES is more important than number of projects.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** As above.	[Ql/Qn] **Unlikely to be a material impact at Tx and Dx level.** Asset location is more important for constraints.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Will require more connections and enabling works but small impact due to overall low number of connections.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Negligible impact on overall costs and emissions of the wider system due to small size of assets.
A higher number of smaller projects could mean projects are **more geographically dispersed. Smaller assets are more likely to be distribution network connected.**	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Assets at Dx level can be less visible to Electricity National Control Centre. Roundtrip efficiency important in times of system stress at both Tx and Dx levels.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Location impacts benefits at all sizes and both Tx and Dx level. Dx connected assets can contribute to Dx operability services, as Tx assets can contribute to NESO services.	[Ql/Qn] **No material impact – but location of assets needs to be considered in assessment to maximise benefits / minimise risks to constraints costs.** This would apply to schemes of any size.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Issues remain consistent across both networks.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Negligible impact on overall costs and emissions of the wider system due to small size of assets.
A larger range of LDES technologies will be able to take part in the cap and floor scheme.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Overall quantum of LDES is most important. Greater diversity of assets is potentially helpful to security of supply.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** Different technologies would have different characteristics to support range of operability services.	[Ql/Qn] **Unlikely to be a material impact at Tx and Dx level.** As above, location and overall quantum of assets is more important.	[Ql] **Unlikely to be a material impact at Tx and Dx level**. Overall quantum and number of connections is most important -as above, this expected to be low.	[Ql] **Unlikely to be a material impact at Tx and Dx level.** More competitive market but overall system impact (cost and emissions) expected to be negligible.

Background and context

Context to the advice request

The government set out their intent to proceed with the introduction of a cap and floor scheme for LDES in October 2024.[5] This was confirmed in the Government's Clean Power 2030 Action Plan in December 2024. Ofgem have been confirmed as the delivery body for the scheme.

DESNZ have formally asked NESO for advice to support the design of the scheme. This advice is provided in accordance with our statutory duties set out in paragraph 171 of the Energy Act 2023. The information included in this response is intended to support DESNZ and Ofgem in delivering the *Technical Decision Document (TDD)* for the Window 1 of the scheme, which is due to be published in February 2025. Government and Ofgem have stated that Window 1 will focus on projects which can be delivered by the end 2030 or 2033. Further windows are expected to be opened over time.[6]

Long duration electricity storage (LDES) definition and purpose

Long duration electricity storage is a broad term. The government has set out that only those technologies which meet the electricity storage definition in the Energy Act 2023, as well as technical eligibility criteria (e.g. ability to discharge continually for 6 hours or more), would be eligible to receive support through the scheme.[7] While there is currently no common standard 'minimum duration' to qualify as LDES, prior DESNZ consultation[8] and the study published alongside this[9] has proposed a 6-hour definition.

Technologies such as pumped hydro energy storage (PHES), liquid air energy storage (LAES), compressed air energy storage (CAES), flow batteries and metal-air batteries would fall under this description. It is these technologies that we focus on in this report, and which we refer to as "LDES" throughout.

DESNZ set out in the January 2024 consultation that the *"LDES technologies supported by this scheme would be expected to complement other shorter duration technologies and operate alongside longer-scale storage facilities like hydrogen, serving different demands and customers."* As such longer-scale storage facilities like hydrogen are not

[5] Long duration electricity storage consultation: Government Response
[6] Call for input - LDES Cap and Floor Regime: Our Role, Plan, and response to the DESNZ publication (Ofgem, 2024)
[7] Long duration electricity storage consultation: government Response
[8] DESNZ, 2024
[9] LCP Delta, 2024

considered in the scope of this scheme and we do not consider them as part of this advice request.[10]

In a clean power system, LDES technologies generally provide a means of storing electricity during extended periods of surplus supply for its re-deployment during periods of reduced output. There is currently 2.8 GW of installed LDES capacity in Great Britain, comprised of four pumped hydro energy storage assets in Scotland and Wales. Our *Clean Power 2030 advice to government* set out that LDES assets have the potential to reduce curtailment, constraints and costs while enhancing security of supply and are "*particularly important for longer term flexibility and additional operability needs*". Our two clean power pathways identified levels of 4.6 GW and 7.9 GW of LDES capacity to support the delivery of a clean power system by 2030, with between 50 and 99 GWh on an energy basis.[11] In our *Future Energy Scenarios 24 publication (FES24)*, levels of LDES between 2030 – 2035 ranged from 3.7 GW to 10.5 GW in our net zero pathways (and between 45 and 117 GWh). Of this overall capacity, at least 89% of the MW-capacity and greater than 95% of the GWh-capacity was assumed to be connected to the transmission system.[12] Similarly, earlier broader analysis on resource adequacy in the 2030s published by ESO in 2022, evidenced the benefit that storage assets of increasing duration can provide in supporting adequacy whilst simultaneously helping to address the challenge of meeting net zero.

However, it is not the expectation that LDES technologies alone will cover all the system's needs, especially during long periods of low renewable output. This will require technologies that can provide energy at a much larger scale for longer periods, such as unabated gas generation, power carbon capture and storage (CCS) and hydrogen to power, to ensure future critical stress events can be covered.[13]

The LDES cap and floor scheme

In October, DESNZ confirmed their intention to bring forward the cap and floor scheme, which will be delivered by Ofgem. They also set out their minded-to parameters for the scheme, including minimum capacities and durations for the two technology streams:

- **Stream 1** is for established LDES technologies with a Technology Readiness Level[14] (TRL) of 9. For Stream 1, DESNZ proposed a minimum capacity of 100 MW and a minimum duration of 6 hours.
- **Stream 2** is for novel technologies, with a TRL of 8. DESNZ proposed a minimum capacity of 50MW and a minimum duration of 6 hours.

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[10] Long duration electricity storage consultation (DESNZ, 2024)
[11] Clean power by 2030: Advice to government (NESO, 2024)
[12] Future Energy Scenarios 2024 (NESO, 2024)
[13] Resource adequacy in the 2030s (2022, Published as NG-ESO with AFRY)
[14] Technology Readiness Levels range from 1 to 9, with 9 representing the most mature technologies.

DESNZ and Ofgem have committed to publishing a Technical Decision Document (TDD) in winter 24/25 that will confirm these parameters for Window 1 of the scheme along with their indicative assessment criteria, with input from NESO through this request.

The advice request

DESNZ asked for advice on three questions relating to the design of the scheme:

1. *Outstanding matters we consulted upon in the January 2024 consultation but did not make final decisions on in our October 2024 government response. We plan to make final decisions on these matters this winter when we publish a Technical Decision Document. In particular we would be grateful for advice from an energy system perspective by the end of this year (2024) on the risks and benefits of*
    a. *increasing the minimum duration for a qualifying LDES asset to beyond 6 hours, and what an optimal minimum duration might be; and*
    b. *lowering the minimum capacity required for eligibility for Stream 2 projects.*

2. *The full range of benefits and costs of LDES for the electricity system which Ofgem should be taking into account when assessing project cap and floor applications.*

3. *Analysis to support the decision on the amount of LDES capacity that Ofgem could support with cap and floor agreements through its first LDES allocation round to open in 2025. This can be expressed with a range, please provide this advice in January 2025. Further analysis to enable Ofgem to make the decision on the optimal amount of LDES will be needed in the spring (2025).*

In addition, DESNZ stated that they would *"like NESO to provide ongoing support to assess LDES projects similar to assessments for optimal interconnection capacity between GB and other markets, and the Strategic Spatial Energy Planning (SSEP) to determine optimal locations, quantities and types of energy infrastructure to meet future demand. This is likely to be required from around mid-2025 and will be taken forward through the process for identifying and agreeing new ongoing work packages and responsibilities for NESO."*

This report provides our answers to questions 1a, 1b and 2. NESO provided a response on question 3 separately. In regard to the fourth part of the request NESO has agreed to support Ofgem with the assessments.

Question 1

Approach to questions 1a and 1b

The approach we took to answering these questions consisted of three steps:

Step 1 – Identification of assumptions about the impact: Drawing on NESO expertise, we made a range of assumptions about the potential impacts of the policy changes proposed in these questions. These are set out in the sections below on each question.

Step 2 – Identification of system aspects: We identified a range of system aspects which are relevant to understanding the impact of the proposed policy changes. These are:

- Security of supply
- Operability
- Thermal constraints
- Connections
- Generation costs and emissions

Step 3 – Assessment against each system aspect: We drew on NESO's expertise to make an assessment of how each proposed policy change would affect each system aspect. As part of this, we made a determination about whether this would be best described through qualitative or quantitative means. In most cases it has been more appropriate to answer the question through a qualitative assessment, except for the thermal constraints costs where we conducted analysis using the PLEXOS model. As such, we have not assessed system monetary "costs", but instead a more general view of advantages, disadvantages and risks. In the most part, we considered the impact of the changes against each 'system aspect' separately to one another rather than what the cumulative impact of these might be for a particular LDES asset. We note that a more holistic analysis of individual LDES assets is envisioned for the assessment process once applications are received.

The vast majority of LDES assets in scope for Window 1 are expected to be connected to the transmission system. We have considered both the transmission system and the distribution system. In many cases the considerations are the same. Assets across the transmission and distribution systems are important for security of supply, the Balancing Mechanism operates across both, and our consideration of connections also looks across both without differentiation. However, there are differences from an operability and Electricity National Control Centre (ENCC) perspective. Assets on the distribution system can offer particular benefits for the needs of the distribution network and can, for example, support services such as those procured by the DNO (e.g. Sustain, Secure, Dynamic and Restore) but are less likely to be utilised for ancillary services supporting the transmission system. We also considered the impact of location in certain instances, for example in helping alleviate local constraints. This applies both to assets on the transmission and distribution networks. These points have all been considered within NESO; DNOs have not been consulted. Further work and engagement with Distribution Network Operators (DNOs) may be needed to provide a more detailed picture of any potential impacts at this level.

Q1a. Increasing the minimum duration

Assumed impacts

This question aimed to understand the costs and benefits to the electricity system of increasing the minimum duration for supplying electricity at full power without recharge beyond 6 hours for a qualifying LDES asset and to determine the optimal minimum duration. DESNZ noted in the question that the change in eligibility criteria may result in fewer eligible projects.

LDES assets can operate at different durations by adjusting their power output. It is therefore important to define clearly that a requirement on minimum duration relates to when an asset is operating at its maximum power output.

In providing our views on this question, we made the following assumptions about the impact of increasing the minimum duration beyond 6 hours:

- Projects below 7-8 hours in maximum duration cannot receive support from the cap and floor scheme.
- Fewer projects enter the cap and floor scheme and are therefore fewer available in the market.
- A smaller range of LDES technologies can take part in the cap and floor scheme (however, we note that most innovative LDES technologies are 8+ hours).
- Some projects may reconfigure to reduce capacity to increase duration to meet a higher minimum threshold.

We understand that it is DESNZ's intention that a change in duration threshold would not impact on the overall capacity of LDES that is procured via the cap and floor scheme in Window 1.

Duration assessment

Modelling undertaken for this advice request has indicated 8-hour units are utilised slightly more than 6-hour units in relation to transmission level thermal constraints. However, the location of the asset and its overall capacity and energy were deemed to be more important factors than its duration.

That said, our 2022 resource adequacy study points to clear security of supply benefits of 6-hour storage units,[15] including in mitigating (though not fully covering) the impacts of critical system tightness in wind drought periods.

Note on determining an "optimal duration"
DESNZ asked us to consider the 'optimal' duration length for LDES assets. We consider it is not possible to identify an 'optimal' duration within the narrow parameters of this LDES request. This is because defining an 'optimal' duration is likely to be subjective and highly sensitive to assumptions about other technologies, including interconnectors and short-duration technologies. Such system wide considerations will be part of the modelling carried out for the SSEP.

Security of supply impacts

Overview

Across three of the assumed impacts[16] **of the change, we assessed that while longer duration assets offer security of supply benefits, increasing the minimum duration is unlikely to have a material impact on overall security of supply.** This is because 6-hour assets are still useful as part of a portfolio of assets for maintaining security of supply – as demonstrated in the 2022 capacity adequacy study.[17] However, we note that **there could be a material impact if some units reconfigure, which can only be properly assessed on an individual project basis.** Additionally, the impact of reducing capacity may be offset by increasing duration.

In security of supply terms, the energy storage capacity of an LDES asset is more important than its duration. The power rating of projects is also important, as higher capacity projects can discharge GWh-scale energy stores more quickly during a supply shortfall. From a security of supply perspective, maintaining the current scheme threshold at 6 hours helps avoid excluding projects that have energy storage and/or power ratings that could significantly contribute during stress periods.

Further detail

The 'Resource Adequacy in the 2030s' report[18] demonstrated that the GB system will face longer periods where meeting demand is a challenge in the future, particularly during

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[15] Resource adequacy in the 2030s (ESO, 2022) – note different LDES technologies were not explicitly considered. The study reasoned that by including 6-hour batteries and hydrogen power generation that this might cover the full potential range of storage duration.
[16] New projects below 7-8 hours duration not being available, fewer projects being able to take in part in the cap and floor and a smaller range of LDES technologies being available.
[17] To note: The Resource Adequacy Study shows a 6 hour LDES assets will be beneficial for security of supply, however a system which only contained 6 hour storage (and no longer duration capacity – e.g. gas, CCUS, hydrogen) would not meet our security of supply standard. As noted above these technologies are not considered as part of the LDES cap and floor and in this advice.
[18] Resource adequacy in the 2030s (ESO, 2022)

periods of low renewable output. We expect there to be a growing need for LDES assets throughout the 2030s to support system adequacy. This is reflected in our *Clean Power 2030 Advice to Government* and *FES24*.

As stated above, it is not expected that technologies procured through the LDES cap and floor scheme alone will meet the system's needs, especially during extended periods of low renewable output, (e.g. dunkleflaute) where other technologies are more appropriate. Additional technologies that can provide energy at a much larger scale for prolonged periods, such as unabated gas generation, power carbon capture and storage (CCS) and hydrogen to power, to ensure these critical stress events are adequately covered.[19] Nevertheless, the durations of projects in the LDES pipeline can materially support security of supply within shorter timeframes.

Increasing the threshold duration could potentially exclude some PHES projects from being considered by the cap and floor mechanism, even if they have larger energy storage than other PHES projects with longer durations. The power rating of projects is also important for security of supply, as higher capacity projects can discharge GWh-scale energy stores more quickly to the electricity system during a supply shortfall.

Other factors that may influence the impact on security of supply are asset efficiency (i.e. allowing quicker charging) as well as technological diversity which can help mitigate deployment and operational risks.

NESO plans to produce a report on Resource Adequacy in the 2030s, which is expected to be released in spring 2025. This report may address some of the questions at a portfolio level.

Operability impacts

Overview

The operability assessment considered within-day flexibility, stability, frequency, voltage and restoration. Adequacy (under "security of supply impacts") and thermal constraints are considered separately given their importance to the benefits case for LDES assets. Similar considerations exist for both transmission and distribution connected assets.

Across three of the assumed impacts[20] of the change, we assessed that while longer duration assets do offer operability benefits, increasing the minimum duration is unlikely to have a material impact. This is because 6-hour assets remain valuable as part of a portfolio of assets. However, we note that **there is a potential material impact should some units reconfigure, which can only be properly assessed on an individual**

[19] Resource adequacy in the 2030s (ESO, 2022)

[20] New projects below 7-8 hours duration not being available, fewer projects being able to take in part in the cap and floor and a smaller range of LDES technologies being available.

project basis. Additionally, as for security of supply, the impact of reducing capacity may be offset by increasing duration for operability.

Further detail

Longer duration assets have greater benefit for flexibility, restoration, thermal constraints, and adequacy operability areas across the electricity system (with the latter two covered in the 'Thermal constraints impact assessment' and 'Security of supply impacts' sections respectively). However, 6-hour duration assets are still useful as part of a portfolio of LDES assets. The increasing benefits for operability that come with longer durations should be considered as part of the assessment process to help ensure longer duration assets do form a significant part of the portfolio.

The electricity system at both transmission and distribution level needs assets which can move energy throughout the day. Assets which can do this for longer periods of time will have a greater benefit on the system during prolonged periods of energy shortfall or excess and could reduce reliance on interconnectors.

Our system restoration plan often involves starting up areas of the grid in stages, and longer duration LDES could have a role to play in this. In our most recent tender for restoration services, we have specified a requirement for a minimum of 10-hour duration for both primary[21] and top-up[22], services (transmission-connected) or a 72-hour duration for both anchor and top up services for the distributed restart. This means that for restoration services specifically, with the current pipeline of projects, only transmission connected assets would play a role given the much longer duration needed on the distribution network.

Thermal constraints impact assessment

Overview

Our quantitative and qualitive analysis suggested that there is a small benefit to moving to an 8-hour duration. However, this benefit is highly sensitive to the location of assets, and overall, the location of assets is more important for addressing constraints. There is some risk that assets may be excluded if they cannot reconfigure, and these excluded projects may be in locations that are beneficial to the system.

We undertook two pieces of analysis to better understand the impact of storage duration on thermal constraint costs and asset utilisation. The first demonstrated that increased durations help to reduce constraint costs. As the duration grows there is a gradual diminishing reduction in costs. Once the duration exceeds 20 hours there is limited additional benefit. **It is important to note that our PLEXOS modelling capability only**

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[21] Primary and Anchor services – plants capable of starting up from a shut-down state without relying on an external power supply. These plants can energise and support the stability of part of the network.

[22] Top-up services – provide the necessary support to maintain and complete the restoration process.

assesses the transmission level impacts. However, we would expect similar considerations to apply at a distribution level.

In our second piece of analysis we found that extending storage duration from 6 to 8 hours provides a small improvement in utilisation in this scenario. While both of these point towards higher durations, this should be considered more broadly with the other assessment criteria and the potential role of hydrogen as an inter-seasonal storage vector in the future.

Further details

Methodology

Through our pan-European dispatch model we attempted to assess if there was a measurable reduction in BM costs via the introduction of LDES projects, and how this varied as the duration increased. To do this, we first ran the model under a base case. We than added a single 500 MW LDES project of increasing durations (2 to 24 hours in 2-hour increments), re-ran the model and observed the change in result. We repeated this twice, first adding the LDES project to north Scotland (Zone 8) and then adding it to Cornwall/Devon (Zone F). We present the impact on BM redispatch costs, expressed as Net Present Value Redispatch Cost, over the period 2030–2050.

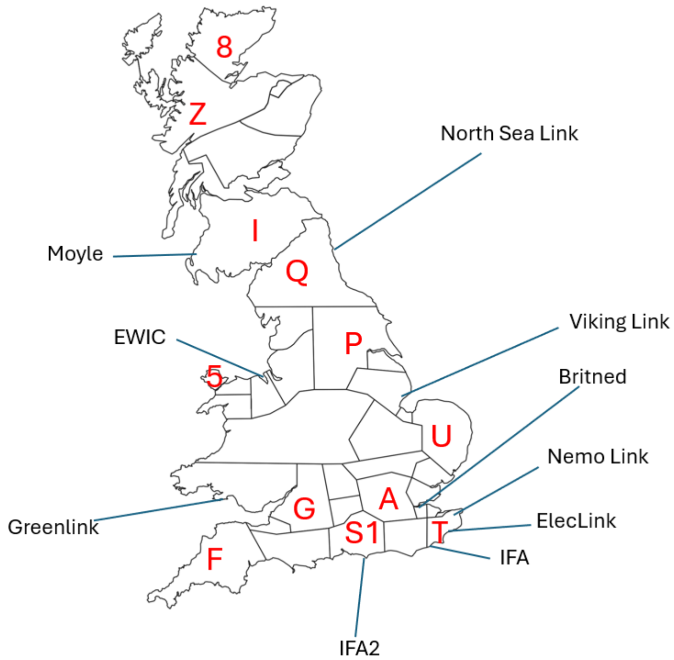

Figure 3. Map showing zone names used in this analysis

Results

As expected, the results show a clear downward trend in redispatch[23] costs as storage duration increases. The inclusion of LDES demonstrates a significant benefit compared to the base case. However, it should be noted that as the duration grows there is a gradual

[23] See box below on Balancing Market.

diminishing in the reduction of costs. Once the duration exceeds 20 hours there is limited **additional** benefit, as shown in the chart below.

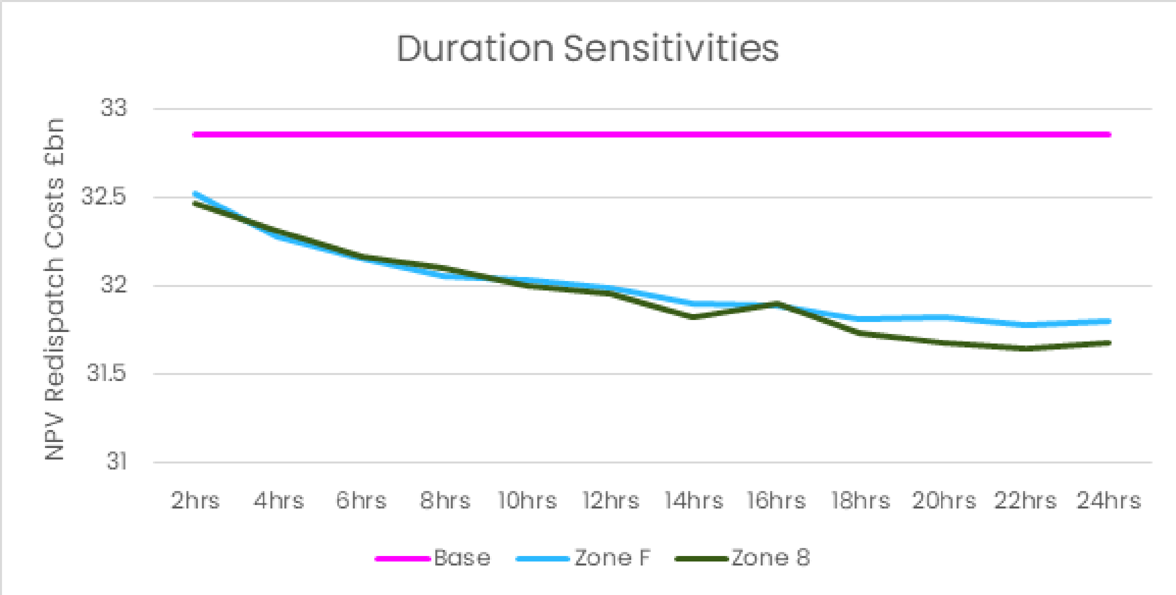

Figure 4. Chart showing BM benefits of 500MW units of additional LDES in 2 different zones. Please note: Redispatch costs are shown as the total over 20 years (2030-2050). This modelling was carried out specifically for this project to provide an indicative view of the benefits of different LDES duration lengths and does not represent NESO's projection of future redispatch costs.

B6 boundary constraints – simple analysis

Further simple analysis was conducted on constrained flows over the B6 boundary (the Scotland-England border), a highly constrained location. We analysed a single scenario for two different years (2030 and 2035). The results showed that:

- In 2030, less than 4% of the constraint events are longer than 24 hours, whereas half of them last up to 2 hours.
- In 2035, with a system more reliant on wind, constraint events become fewer in number but more prolonged: a third of the constraints lasts up to 2 hours, a third lasts between 3 hours and up to a day and the remaining third is greater than a day.

Since many events last up to two hours, it might seem that short-duration storage could be helpful, particularly in 2030. However this overlooks back-to-back events, which may often result in the storage being in an unhelpful state of charge when required for the system.

This analysis involved modelling storage of different durations above the B6 boundary acting exclusively to help with constraints at the transmission level (the system modelling tool does not model distribution network level effects).

The findings indicate that, in 2030, a 6-hour storage utilisation rate would be 26%, while an 8-hour storage would have a utilisation rate of 30%. In 2035, those utilisation rates would be 14% and 16%, respectively. This decrease in utilisation is due to the B6 boundary being much more constrained in 2035, with many events being much longer than 6-8 hours and the reduced capability of the storage to cycle to support back-to-back events. The utilisation rate is a measure of how often the storage system operates (i.e. is charging or discharging).

Increasing storage duration to 20 hours would increase utilisation to 43% of the time in 2030 and 28% in 2035.

Figure 4: Utilisation in relation to constrained flows over the B6 boundary

Duration (hrs)	Utilisation	
	2030	**2035**
6	26%	14%
8	30%	16%
20	43%	28%

In this scenario, the storage would benefit the system for half the time that it operates by alleviating constraints when it charges, and for the other half by providing zero carbon electricity when it discharges.

In conclusion, extending storage duration from 6 to 8 hours provides a small improvement in utilisation in this specific scenario. However, it is important to note that this analysis considered an extreme case of a very constrained boundary, where constraints tend to follow the patterns of wind duration, which typically last for days. In this case, much longer durations are needed to provide significant benefit. The results of this study cannot be generalised across the energy system given the specific nature of the study. However, it does highlight how optimal duration may differ by location depending on the specific needs of that region over time.

Connections impacts

Overview

Our assessment found no material impacts on connections. Increasing the minimum duration for assets in both streams may reduce the number of assets that come forward to seek connection, but we do not expect the scale of this to result in any material impact on the use of connection bays either on the transmission or distribution networks given the relatively small number of connections for LDES in Window 1.

The Clean Power 2030 Action Plan outlines capacity breakdowns for each technology required for 2030 and 2035, and for battery storage these capacities are significantly less than the total MW volume of battery storage capacity in the connections queue at present. This could incentivise developers of short-term battery storage to reconfigure their projects and be categorised as LDES in order to increase their chances of remaining in the connections queue, as well as allowing them to qualify for the cap and floor scheme.

The timings of the new connections process also introduce an uncertainty for the contracted connection dates of LDES projects applying in Window 1, as projects in the connections queue today will be reassessed and their connection dates potentially revised as a result. However, we have committed that all projects that have secured planning consent will be included within the reformed connections queue.

Individual connection agreements may be affected by any reconfiguration of assets to meet an increased duration limit, but this is a matter for developers.

Generation costs and emissions impacts

Overview

We considered whether increasing the duration of the LDES assets to 7-8 hours could lead to LDES technologies displacing, or being replaced by, other generation technologies in the electricity market, with corresponding economic and emissions impacts. Although we were not able to model this with our current PLEXOS capabilities, **we consider it is possible that there could be material differences in costs and/or emissions benefits of projects of 6-8hours, which would be excluded from the scheme. The benefits and costs of these projects could be determined through the application assessment process if the 6-hour minimum duration requirement is maintained.**

Further detail

Increasing the threshold duration could potentially exclude some PHES projects in the current project pipeline from being considered under the cap and floor mechanism if they cannot reconfigure to meet the higher duration threshold.

As stated previously, we have made a general assumption that the change in duration threshold does not impact on the overall capacity of LDES that is procured via the cap and floor scheme in window 1. Consequently, we assume that longer duration PHES projects or other LDES technologies would replace excluded projects.

However, this means there is a smaller pool of projects being relied upon, and the opportunity to assess individual projects on their merits, such as better cost and/or emissions benefits, is missed.

It is notable that Dinorwig, one of the four pumped storage assets currently in-operation[24], can be considered to be an approximate "5- to 6-hour asset". This asset has a greater energy capacity (GWh) than any of the other existing PHES schemes (Ffestiniog, Cruachan, Foyers) which are of longer duration. This is an example of a project that is important to the GB energy system despite only approximate 6 hour duration.

Based on our understanding PHES projects there are several that could be impacted by an increase in the minimum duration threshold. Without passing the pre-qualification stage, there would not be the opportunity to make a more comprehensive assessment of their system benefit.

[24]See BHA, 2024 for an overview of MW and GWh capacity of these schemes.

The impact of changing the threshold on more innovative LDES technologies is mixed and less clear. This is because several potential projects may be excluded from the scheme on other grounds (e.g. TRL) anyway. However, considering the seven innovative LDES technology developers we have previously engaged with, six have indicated they can deliver storage assets with a duration of 8 hours and above.

There could be competition with batteries in the 6-hour range as battery pack prices have been falling significantly and are likely to continue to do so. This is assumed to only impact the Stream 1 funding (i.e. TRL9). It is therefore unclear at this stage how many 6-hour batteries will apply for the cap and floor mechanism (if they are eligible), how competitive they will be, and whether their system benefits will outweigh those of other proposed projects. These factors can only be analysed with further information (e.g. CapEx costs, project location, etc) which we assume will be provided during the assessment process.

Q1b. Reducing the minimum capacity from 50MW

Assumed impacts

This question[25] focused on understanding the electricity system costs and benefits of lowering the minimum capacity required for eligibility for Stream 2 projects to below 50 MW.

In providing our views on this question, we made the following assumptions about the impact of reducing the minimum threshold for Stream 2 to below 50 MW:

- Smaller capacity projects, below 50MW, will be supported through the cap and floor scheme (and will therefore be available in the wider electricity market).
- A larger number of smaller projects will receive support through the cap and floor scheme and be available in the market.
- A higher number of smaller projects could mean projects are more geographically dispersed. Smaller assets are more likely to be distribution network connected.
- A larger range of LDES technologies will be able to take part in the cap and floor scheme.

As above, we made the important cross-cutting assumption[26] that a change in the minimum threshold would not impact on the overall capacity of LDES that is procured via the cap and floor scheme.

Security of supply assessment

Overview
The security of supply assessment considered both capacity adequacy (is there sufficient capacity available on the system) and real-time operational considerations in a potential stress event. **Our assessment identified no material impacts from a security of supply perspective in reducing the minimum threshold for Stream 2 to below 50MW.**

While LDES technologies will be an important component of ensuring we maintain security of supply in a clean power system, the overall size of the storage portfolio, measured in terms of energy (GWh) and capacity (GW), holds greater importance to security of supply than the number or individual capacity of the assets within it. That said, individual

[25] DESNZ noted in the question that that an increase in the number of small projects eligible to apply, the longer it could take for Ofgem to make cap and floor decisions on larger projects.
[26] This "cross-cutting assumption" interacts with all other assumptions and was held constant across all "system aspects".

characteristics of different plant, and their visibility to the Electricity National Control Centre could have a bearing on real-time operation and managing the system in times of stress.

Further detail
It should be noted that certain characteristics of the individual assets (not considered here) may have consequences such as the round-trip efficiency that could influence the speed at which stores can be re-charged. This may be important following a stress event, particularly if there are multiple stress events occurring just a few hours apart. However, for small assets (such as those under 50MW) this is not considered to be material.

The visibility of and access to assets by the Electricity National Control Centre[27] (ENCC) is important for enabling coordinated redispatch at times of system stress (see 'Participation in the Balancing Mechanism' box). For example, if the LDES asset is available for coordinated redispatch, for example through the Balancing Mechanism (BM), this gives the opportunity for the ENCC to optimise its use during a situation of system stress, i.e. to ensure it is fully charged prior to the start of stress event. Although visibility and access to assets below 50MW may be impacted by the higher likelihood of being on the distribution system and the current absence of a requirement to participate in the BM, this is not considered to have a material impact on security of supply given the size of the assets.

As set out in our assumptions, reducing the capacity threshold below 50 MW could lead to a greater spread of smaller units. This is unlikely to materially impact security of supply. We also set out in our assumptions that a larger range of LDES technologies may take part with a reduced threshold. Generally, a greater diversity of assets is helpful to security of supply, though we do not expect this impact to be material at the scale of assets considered here.

Operability impacts

Overview
The operability assessment considered within-day flexibility, stability, frequency, voltage and restoration. Adequacy (under "security of supply") and thermal constraints are considered separately given their importance to the benefits case for LDES assets. Our SMEs identified similar considerations exist for both transmission and distribution connected assets.

Our assessment identified no material impacts on transmission or distribution system operability from reducing the minimum threshold for Stream 2 to below 50MW. As with security of supply, it is the overall volume of capacity and energy available on the system which is the most important to consider. However, the location of assets can have a

27 What does the Electricity National Control Centre do? (NESO, 2023)

significant impact on the benefit a particular LDES asset has to the system and should be considered in the assessment process to help maximise benefits.

There are currently challenges in maximising the benefit of LDES assets to the transmission system that are located on the distribution system due to limitations around controllability and visibility of assets, but work is underway to address these which we expect to complete before new LDES projects are completed[28]. Distribution system impacts may vary from network to network. As noted above, we have not engaged Distribution Network Operators (DNOs) in developing this advice, but DESNZ and Ofgem may wish to consider engagement with them prior to finalising the scheme design, which we can help facilitate.

Further detail
Electricity network operability means maintaining a stable, reliable and efficient power grid. It means ensuring the system can handle fluctuations in supply and demand, integrating renewable energy sources and responding to potential disturbances or faults. As Great Britain transitions to a clean power system, the operability challenge evolves. Chapter 2.9 of our *Clean Power 2030 Advice to Government* sets out the various operability challenges of a clean power system.

NESO's operability services, or markets, are the main way we secure assets to support system operability at a transmission system level. New operability services and markets have been brought online over the past five years to meet future operability needs as the system decarbonises. These have encouraged participation from a variety of assets, including small assets, thus increasing market liquidity.

If the pool of market participants grows due to a reduction in the minimum capacity for Stream 2 this could further increase liquidity. However, we would expect the impact to be immaterial in the context of the wider system.

If reducing the MW-threshold also increases the number of locations where assets can be located, this may also have benefits in areas where there are relatively few providers delivering ancillary services. However, any such locational benefits are not guaranteed given they depend on LDES developers' choice of location (see 'Locational Signals' box).

Smaller assets are more likely to be connected to the distribution network, and these could help support the specific operability needs of the distribution network. For example, providing the flexibility services that are procured by DNOs (e.g. the Sustain, Secure, Dynamic and Restore services). However, such assets would need to be capable of meeting the requirements of those services and these capabilities may differ by technology type.

Distribution connected assets are more likely to be beneficial to their distribution network than assets connected to the transmission system, and vice versa. For example, the ESO

[28] These are highlighted in internal NESO operations policy documents (not in the public domain).

Pathfinder Programme[29] has indicated that assets connected to the distribution network are less effective than those connected to the transmission system at helping to manage transmission voltage or supporting the transmission system after a fault occurs.[30] From a transmission perspective, there are challenges associated with the visibility of assets connected to the distribution network.[31] This issue is most relevant to the frequency and thermal areas of operability as changes to MW output from distribution assets has an impact on both networks. However, whilst these challenges exist today, NESO is pursuing efforts to alleviate such problems.

The NESO Distributed Energy Resources Visibility Programme, which will include consumer and demand side flexibility in scope, will aim to improve real time operations, market facilitation and strategic planning. The programme vision is for GB electricity system and network operators to have visibility and access to assets on the distribution network across all timescales to optimise delivery of end-consumer benefits. NESO are committed to collaborating with the industry to enhance real-time visibility of DERs. Achieving visibility and access of distributed assets requires a significant industry-wide transformation of business, policy, technology and data changes, and is key for enabling Clean Power 2030. As a result of this programme, therefore, we anticipate that the visibility and access challenges associated with distribution-connected assets can be managed by the time the cap and floor-funded LDES assets come online in the 2030s.

Thermal constraints impact assessment

Overview

In operating the electricity system, there are times when the physical capacity of the network cannot transfer the amount of electricity required from point of generation to points of demand. When this happens, generation output needs to be reduced and this is called a 'constraint'. The thermal constraints assessment used our pan-European market dispatch model to assess the impacts of reducing the minimum capacity threshold to below 50MW.

Our assessment was not able to determine if there were any material system benefits or costs to having LDES units of under 50MW, as this is within the bounds of uncertainty and tolerances within our modelling. Furthermore, if projects have the same efficiencies, ramping characteristics and storage duration and participate in the BM, then it is the

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[29] Network Services Procurement was previously called the Pathfinder programme. Network Services (NESO, 2024)

[30] Voltage services do not travel well between voltage levels. Voltage (reactive power) services delivered by assets connected to a Distribution circuit have limited impact on the voltage on nearby Transmission circuits, and vice versa.

[31] For example, assets connected under locally Active Network Management (ANM) may not be able to run when requested to by the ENCC due to restrictions relating to the ANM-affected area. The net effect is no change from prior to NESO's dispatch instruction. There are no arrangements currently in place to prevent assets under ANM schemes from participating in ancillary services.

aggregate capacity in each zone that is material to the outcome, not the breakdown of this capacity between sites.[32]

Further details

The electricity network has a finite level of capacity. This means that at periods of high demand and supply there are limitations on how much electricity can flow from one part of the network to another. When this occurs, this is considered a constraint - where the system is unable to transmit power due to congestion at one or more parts of the network.

To overcome a constraint, and therefore ensure system security, NESO must take an action to either reduce generation or increase demand behind a constraint, and instantaneously undertake a corresponding action on the other side of the constraint to ensure that supply and demand balances nationally. These actions are enacted through the BM and have an associated cost paid to generators and recovered from consumers.

Through our pan-European dispatch model we attempted to assess if there was a measurable reduction in BM costs via the introduction of LDES projects, particularly those smaller than 50 MW. We made the important assumption that all these assets are participating in the BM (see section on BM participation below). To do this, we first ran the model under a base case. We than added a single 6-hour LDES project of increasing capacity (5 MW, 10 MW, 15 MW, etc), re-ran the model and observed the change in result. The results observed within this 5 to 50 MW range were deemed to be too small to fully assign them to the LDES project instead of the in-built error tolerance of the model. Logically, smaller projects could still help reduce BM costs, albeit by a small amount, subject to them participating in the BM. At above 50 MW there was a significant and measurable trend of increasing benefit with increasing capacity.

While our analysis attempted to quantify whether a single LDES unit of small size can have a measurable impact on BM costs, the question of size threshold goes beyond this. For example, the question could be expressed as “are 10 x 50 MW LDES projects better than 100 x 5 MW LDES projects?”. If all the projects have the same efficiencies, ramping characteristics, participate in the BM and are located in the same zone on the network, then the two situations are identical from a BM costs perspective in our pan-European market dispatch model.

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[32] Zones in this context refers to the different zones in the GB transmission system used in the PLEXOS model. See “Thermal constraints impact assessment” for Question 1a for more detail.

Participation in the Balancing Mechanism

The Balancing Mechanism (BM) is the tool used by NESO to achieve energy balance across the transmission system, and is the way in which assets are visible and controllable by the ENCC. These assets can be "redispatched" at times of system stress which means that the ENCC instructs assets to turn on or off to ensure generation meets demand across the transmission system at all times. Generally speaking, a greater number of smaller units (as opposed to a smaller number of larger units) requires more data and robust and effective tools in order to dispatch them effectively.

Currently, the threshold for default participation in the BM varies across Great Britain: approximately 50 MW in England and Wales, 30 MW in South Scotland, and 10 MW in the North Scotland. Within Balancing and Settlement Code (BSC) forums, there is on-going work on Grid Code modification GC0117 that is considering amending the MW size threshold for mandatory BM participation. This would change grid code requirements to mandate the definition of Large Power Stations as 10MW and above. If implemented, this change would require LDES units in the 10-50 MW range to default into BM participation. However, we would expect most LDES assets to participate in the BM even without this requirement given it would form a significant proportion of their revenue stream.

It is possible that smaller LDES storage units can be deployed closer to areas with high demand or where the grid is weaker. This localised approach could aid in alleviating constraints not only on the transmission network but also on the distribution networks. Placement of storage units is crucial to determining their impact: if they are strategically located in areas where reinforcement is most needed, they may alleviate stress on the grid and reduce the need for upgrades. Conversely if LDES assets are not well-placed, they may not effectively address grid constraints or could make them worse. However, there are currently no clear incentives for developers to place generation in particular locations – see the box below.

In stakeholder engagement with NESO some developers of emerging LDES technologies indicated a preference to build smaller-scale projects, for reasons including difficulty in financing a 50 MW project at this stage. We assume that lowering the 50MW threshold for Stream 2 could allow enable a wider range of LDES technologies to take part in the scheme. Newer forms of LDES can in theory be deployed in a wider range of areas (e.g. areas that do not benefit from mountainous areas for pumped hydro or offer suitable caverns for large-scale gaseous storage). As such there are potential longer term locational benefits to encouraging innovation in LDES. However, at the scale of assets discussed in this question (below 50MW) this is not deemed to have a material impact in the wider context of the system.

Locational signals

We make reference to the dependency of location for some of the potential benefits of LDES in different parts of the report. Currently, there are not clear market signals to support optimal location of assets on the electricity system. In future the Strategic Spatial Energy Plan (SSEP), Regional Energy Strategic Plans (RESP) and Review of Electricity Market Arrangements (REMA) may all have an impact on locational signals for LDES. However, the timing of any interventions arising are not likely to have an impact on siting decisions for projects funded in Window 1 of the cap and floor. It should also be noted that "optimal location" for LDES may change over the lifetime of an asset.

In this light we conclude that any potential benefits dependent on location are not yet sufficiently certain or achievable to influence decisions under question 1 for the first cap and floor window.

Connections impacts

Overview

Following the publication of the government's Clean Power Action Plan, NESO and Ofgem are delivering a programme of connections reform to ensure the future connections queue is formed of 'ready' projects that are aligned with strategic energy plans. This will enable the capacity required to deliver clean power by 2030 to connect to the transmission and distribution networks.

In theory, a larger number of smaller units would result in a need for additional connections and the associated enabling works at transmission and distribution level. **However, given the relatively small number of LDES connections in question for the first cap and floor window, we assess that these impacts are unlikely to be material in the context of the wider system.**

Generation cost and emissions impacts

Overview

We considered whether reducing the minimum threshold for Stream 2 to below 50 MW could lead to LDES technologies displacing, or being replaced by, other generation technologies in the electricity market, with a corresponding economic and emissions impacts. **Given the scale of the assets in question (below 50MW) we did not assess the impact to be material.**

Further detail

Our assessment did not include a quantitative analysis of the impacts of reducing the minimum threshold for Stream 2 to below 50MW. This is because, as set out above, the impact is likely to be within the margin of error of our model and below the level of granularity that can be modelled effectively in the context of the wider system.

Q2. Assessment Criteria

Approach to Question 2

This question asked for our view on *"the full range of benefits and costs of LDES for the electricity system which Ofgem should be taking into account when assessing project cap and floor applications."*

To answer this question, we drew on NESO experience and expertise in assessing applications for the interconnector cap and floor regime. In that process, the cost-benefit analysis was divided between Ofgem, National Grid ESO and Arup. We looked across the work of all three organisations and determined whether similar analysis would also be required for assessing LDES projects. Finally, we supplemented this with additional assessment criteria that are unique to LDES projects.

A key difference with the interconnector cap and floor is the number of assets that are likely to require assessment. Time and resources are likely to prohibit a thorough assessment of every potential cost and benefit. It may therefore be necessary to prioritise the most material costs and benefits to assess quantitatively. We have therefore provided a guide to which elements we consider are likely to be the most material.

We have split our assessment into those associated with socio-economic welfare, other system costs and benefits, and non-system impacts.

Please note: We have set out the suggested criteria for assessment below agnostic of who the assessment is carried out by. As noted above, DESNZ have asked NESO to support Ofgem with the assessments, which NESO has agreed to undertake.

Socio-economic welfare

We propose that each project be assessed to determine the impact it has on the welfare of three economic groups: consumers, producers and LDES owners. Metrics should be calculated on a Net Present Value (NPV) basis using an agreed discount rate and x-year period, where x represents the duration of the cap & floor regime.

Consumer welfare

Consumer welfare refers to the overall well-being and satisfaction of consumers in an economic market, in this case the power market. The addition of a new LDES project will impact consumer welfare as it will alter the prices consumers pay in the wholesale market and various other markets/schemes. Consumer social-economic welfare (SEW) includes:

1. Change in wholesale market prices due to the addition of each LDES project. This has a direct impact on the cost of electricity for consumers.
2. Changes in Balancing Mechanism costs. Consumers incur costs through actions taken in the Balancing Mechanism (BM) to overcome constraints in the market

resolved generation mix. As an example, the current wholesale market with a single national price can result in too much generation in one part of the country. Without the ENCC taking actions through the BM this will result in a thermal overloading over power lines. The ENCC therefore accepts bids and offers from the generators to adjust the market position to resolve the constraints. These bids and offers have associated costs which are passed on to consumers. The addition of a new LDES project may affect the frequency and size of the bid and offer actions taken, thereby affecting the welfare of consumers and producers. This results in a transfer of payments between consumers and producers.

3. Change in payments from or to consumers under the cap and floor regime (i.e. the cost to the consumer of providing a cap and floor to each project). This represents a transfer of welfare between consumers and the project developers with sites operating under a cap & floor regime, such as Interconnectors and the LDES projects themselves.
4. Changes in the costs of the Capacity Market. Security of supply is ensured through payments to generation assets that were successful in the Capacity Market auctions. These payments are intended to ensure that electricity generators are available to supply consumers particularly when there is a 'missing money' element under the other markets generators participate in. The cost of the Capacity Market payments are recovered from consumers. New LDES projects can impact consumer welfare through changes in the costs of the Capacity Market. This is a transfer of welfare from consumers to producers and LDES projects.
5. Changes in the costs of the Contract for Difference (CfD) scheme. There are a number of existing projects, such as offshore wind, that are financially supported through the CfD scheme. This guarantees them a stable level of revenues at the agreed 'strike price'. When the wholesale market price is below the strike price, then the generator receives a top-up to the strike price, paid for by consumers. Conversely when the wholesale market price is above the strike price, then the difference is paid back from producers to consumers. This is therefore another example of a transfer payment. The addition of an LDES project will affect the wholesale price and therefore the consumers exposure to CfD costs.

To measure the impact of an LDES project, analysis would need to be undertaken in a market dispatch type model (e.g. BID3, PLEXOS). The analysis would include a comparison of the outputs of the model with each LDES project to the counterfactual case representing the initial state of the market without the LDES project. The difference between the two model runs gives the impact of each project.

As each LDES project added in turn will affect the behaviour of all the other LDES projects, it is important to account for the build profile. To do this, it is likely that a similar process as was deployed for assessing interconnectors under the interconnector cap & floor assessment would need to be followed. In this, two different build profiles were considered:

- the First Additional (FA) case, where the project assessed is the first and only one among the candidates to be built; and
- the Marginal Additional (MA) case, where the project assessed is the marginal (last) project of the candidates to be built.

The details of this approach would be further refined when more detail about the cap and floor scheme becomes available. For example, the design would depend on whether all projects have the same connection date or whether they are staggered. It is also worth noting that while this approach has been applied before in assessing interconnectors, this was against a relatively small number of projects (9). The appropriateness of this approach for assessing LDES sites would need to be considered in regard to the potential number of LDES projects and the available timeline for assessment.

Calculating the impact on the Capacity Market will need to be done outside of the market dispatch model. Further consideration is required as to how, and which organisation, is best placed to undertake this assessment and any enabling research or analysis which would be required prior to beginning any assessments. It would first require an assessment or consideration as to whether greater LDES participation in the Capacity Market results in a change in the clearing price. For the purpose of the interconnector cap & floor assessment, it was assumed that the clearing price was unchanged.

Producer welfare

The introduction of new LDES projects impacts on producer welfare primarily through changes in revenues associated with the wholesale market price and payments to and from producers through CfDs:

1. Changes in wholesale market prices due to the addition of a new LDES project. This will affect the gross margin for energy production received by producers.
2. Changes in Balancing Mechanism (BM) revenues as a result of a new LDES project. It is expected that a well-placed LDES project could reduce the number of actions taken in the BM to overcome thermal constraints and therefore reduce the revenues producers receive from the BM.
3. Changes in revenues producers receive under the CfD scheme. See explanation above under consumer welfare.

These can be calculated using a market dispatch model.

Long Duration Electricity Storage welfare

LDES projects will see a change in welfare when new projects are added, primarily due to the change in revenues earned through arbitrage (where assets are bought in one market and sold in another for a higher price) as the wholesale market price at time of charge and discharge is affected. There are also payments through the cap & floor regime and costs associated with the LDES project under consideration:

1. Changes in revenue from arbitrage payments captured by the LDES owners. These revenues depend on the price differentials between charge and discharge.
2. Changes in Balancing Mechanism (BM) revenues as a result on a new LDES project. If an LDES project participates in the BM it will earn revenues.
3. Changes in Capacity Market revenues earned by the LDES project.
4. Changes in the payments from or to consumers under the cap and floor regime based on the revenues earned by the LDES projects. For each project, revenues

from arbitrage payments and Capacity Market revenues are summed together before being compared to the respective cap and floor levels.

5. Cannibalisation of revenues where changes in electricity supply/demand in each settlement period, and therefore the price differentials between the wholesale market price at time of change and discharge, lead to higher or lower revenues on existing LDES projects.
6. Cost of constructing (CapEx) and operating (OpEx) the LDES project including the losses incurred on a charge/discharge cycle. This would require developers to provide input data and for a full assessment it should include the cost of the network works required to connect the LDES project.

As with the above sections, a market dispatch model can be used in undertaking this analysis. CapEx and OpEx data will be required from the developers, along with information about the energy losses incurred over a charge / discharge cycle. If these losses increase as the time between charge and discharge increases, we will need to agree some assumptions to apply.

Note on modelling capabilities

The PLEXOS model would be well suited to carrying out the assessments on socio-economic welfare, however it would require significant configuration prior to the assessments taking place. Further consideration is required as to how, and which organisation, is best placed to undertake the part of the Capacity Market assessment that needs to be done outside of the market dispatch model.

Other system costs and benefits

Decarbonisation

An assessment here could be to measure the potential change in carbon dioxide emissions in GB as a consequence of adding the LDES project. To do this on a full lifecycle basis requires information about the carbon emitted during the construction of the project along with any direct emissions that materialise due to the ongoing operation of the site. Through market dispatch modelling an assessor could determine the change in emissions of the overall generation mix utilised to meet the level of demand throughout the study period.

Results could be presented based on the UK Emissions Trading Scheme cost of carbon, or the societal cost of carbon.

Security of supply

We propose that this is assessed, however, at this stage it is unclear if it needs a separate assessment or will form part of the assessment on welfare from the Capacity Market. We would expect to refine these details following further discussion with Ofgem and DESNZ.

For LDES projects connected to the distribution network, information about any Active Network Management (ANM) control in place and how they affect the LDES project's ability to contribute to security of supply would be required.

System operability

This assesses the potential savings that an LDES project may provide to the grid through the provision of ancillary services, for example reductions in costs of procuring frequency response or reactive power services.

The services to consider are:

- Frequency response – the potential impact of the projects on system frequency.
- Reactive power – the potential impact of the projects on system voltage.
- Restoration – the potential impact of the projects on restoring power to the system in the unlikely event of a power outage. Previously referred to as Black Start.

It is expected that the results here will be an order of magnitude lower than the SEW costs and as such it may be an element to remove from the scope of any assessment. This can be decided as we get greater clarification of the timelines for an LDES cap & floor assessment, along with the number of projects to be assessed. Ofgem should consider the potential for different technologies to provide these services when designing the assessment criteria.

For LDES projects connected to the distribution network, information about any Active Network Management (ANM) control in place and how they affect the LDES project's ability to contribute to system operability at a transmission level would be required. It may also be important to consider the impact on the operation of the distribution network.

Renewable integration

Under this indicator the potential volumes of renewable energy supply (RES) curtailment that can be avoided when an LDES project is connected to the grid would be assessed. While this can be reported out of a market dispatch model, it should be noted that this is not mutually exclusive to other assessment criteria. For example, there is a strong overlap with the carbon emissions criteria above.

Connection implications

As noted in our response to question 1, we consulted on proposals for reforming the connections process earlier this year. Some smaller projects have been using scarce substation bays at higher voltages. While there are currently no industry standards dictating the voltage a project should connect at based on its capacity, if standards emerge prior to the assessment date one could assess whether each LDES project aligns to these new standards.

Furthermore, in time we would encourage alignment with the outputs from the Strategic Spatial Energy Plan (SSEP). The first SSEP is due to be delivered by the end of 2026, however data will become available for use within DESNZ from Q4 2025 onwards so may not be available at the time of the cap & floor assessment for Window 1.

Note on modelling capabilities

The PLEXOS and BID3 models would be well suited to carrying out the assessments of the majority of the system benefits described in this section, however, would require significant configuration prior to the assessments taking place. Some elements would require refining as further details about the cap and floor scheme become available.

Further consideration is required as to how, and which organisation, is best placed to undertake the part of the Capacity Market assessment that needs to be done outside of the market dispatch model. Connections impacts would not require modelling to assess.

Non-system impacts

We suggest that these non-system impacts be considered alongside an assessment of electricity system costs:

- Environmental impact
- Local community impact
- Interactions with other uses of key shared resources (e.g. land space and water).

For the most complete assessment, both the impacts of the LDES project itself along with the impact of local network works to enable its connection, should be included.

Regarding the third bullet point above, we advise that Ofgem should have some way of assessing schemes which use the same resource even if they are not in the same Window. It is plausible that a combination of projects located in a similar geographical area could have a negative combined impact if all projects proceed. Such effects may be associated with the local environment (e.g. wildlife) or on shared infrastructure (e.g. roads, electrical infrastructure).

Assessment tools and approach

Much of this section will be assessed through the planning and consenting process. We have assumed this will have taken place prior to cap and floor assessments. **Ofgem should consider how best these considerations are factored into their decision making and what assurance they need on the information provided. However, we have not considered them in detail as they fall outside the scope of the question, which focuses on "electricity system" costs and benefits.**

In time, developments to our strategic energy planning process, including the Centralised Strategic Network Plan (CSNP) and SSEP may provide useful information to support future cap and floor decisions. Finally, and as noted above, we advise that Ofgem should have some way of assessing schemes which use the same resource even if they are not in the same Window.