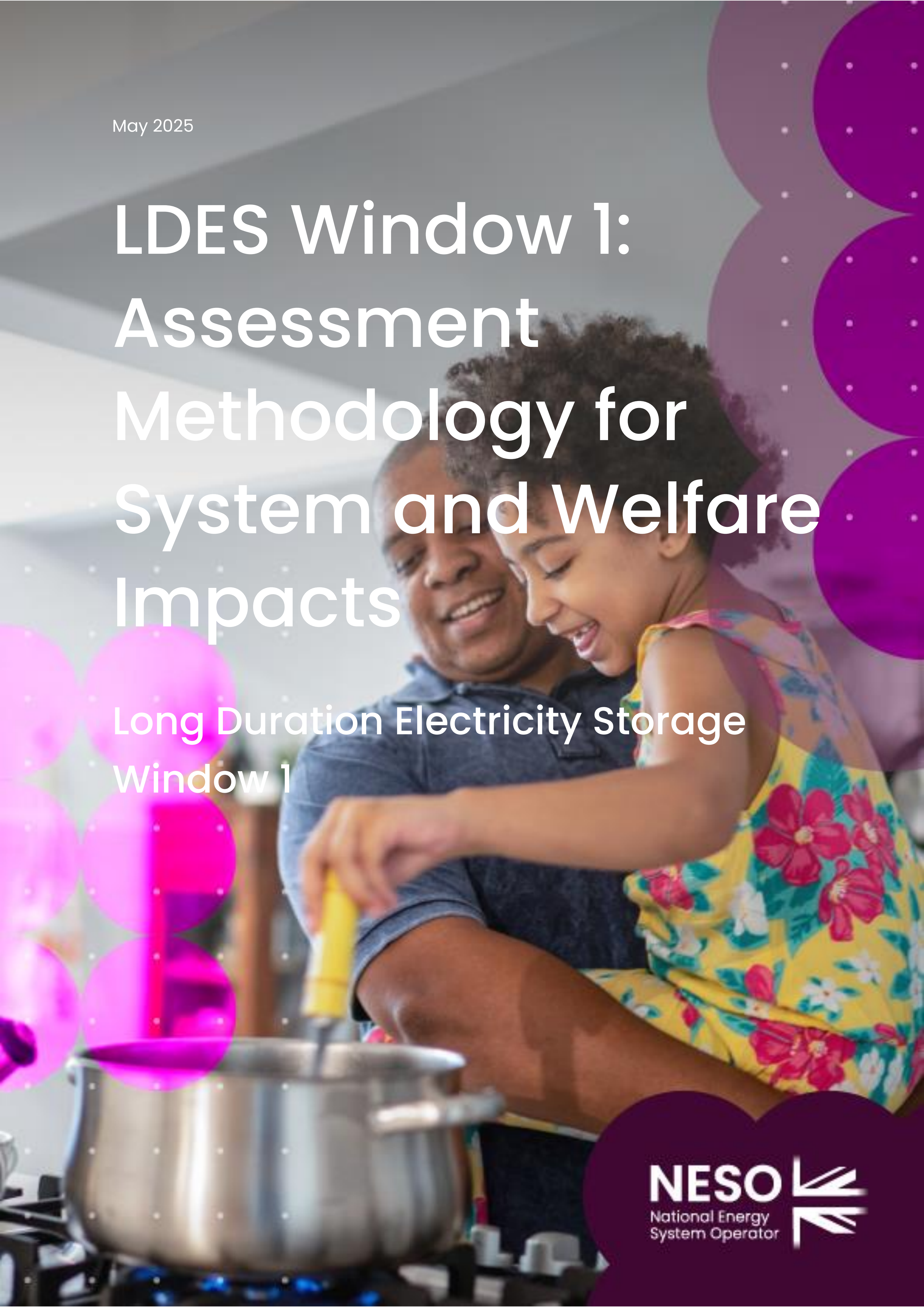
May 2025

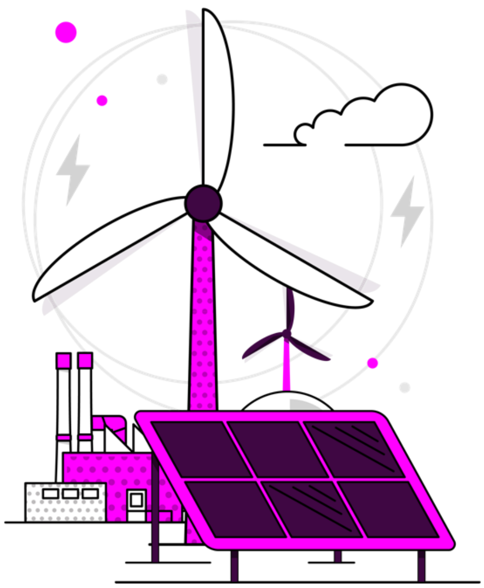
# LDES Window 1: Assessment Methodology for System and Welfare Impacts

## Long Duration Electricity Storage Window 1



NESO
National Energy System Operator

# Table of Contents



# Executive Summary

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The Long Duration Electricity Storage (LDES) cap and floor scheme is being developed by Ofgem, supported by the National Energy System Operator (NESO). This initiative is intended to catalyse investment in LDES technologies, which are essential to providing flexibility, security of supply, and decarbonisation in a future net zero energy system. Under the scheme, Ofgem will regulate the investment environment through a cap and floor mechanism, offering revenue certainty to developers while protecting consumers.

As part of the scheme's delivery, NESO will undertake a detailed benefit analysis for each applicant. NESO will assess the value that each project is expected to deliver across a range of system and consumer benefits. This analysis will inform Ofgem's decisions on awarding the cap and floor regime and enable Ofgem to rank projects based on their net benefits.

The CBA will assess a range of monetised benefits, including:

- Reductions in wholesale electricity prices and constraint management costs (consumer welfare)
- Impacts on generator and storage operator revenues (producer welfare)
- Security of supply improvements
- Carbon emissions reductions

A key feature of the methodology is the use of a Marginal Addition (MA) approach. Each project is assessed against a consistent counterfactual scenario in which all non-committed LDES capacity are removed and replaced with a notional, evenly distributed archetype. This ensures a fair and transparent comparison of each project's incremental value.

Smaller projects may be grouped for assessment to ensure modelling efficiency, with benefits allocated proportionally. Sensitivities such as an alternative energy scenario, zonal pricing, and extreme weather years are planned.

This consultation seeks stakeholder feedback on NESO's proposed CBA methodology, including the modelling approach and benefit components. The final framework will be published in Q3 2025 and will underpin the assessment of projects applying in the first LDES Cap and Floor application window.

# 1. Introduction

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This document outlines the role of the National Energy System Operator (NESO) in the cost-benefit analysis (CBA) component of the Long Duration Electricity Storage (LDES) Cap and Floor scheme. Ofgem has assigned NESO the task of creating a scope of work to quantify the benefits of projects applying for funding under this scheme. The scope of work is detailed in this document and will undergo consultation from the broader industry. The final CBA framework document is scheduled for publication in Q3 2025.

The LDES Cap and Floor scheme is being introduced by Ofgem, following direction from DESNZ, to help address potential delivery risks associated with emerging storage technologies. These technologies are expected to play a key role in achieving the UK's 2030 decarbonisation targets, as highlighted in previous NESO analysis under the Government's request for advice on Clean Power 2030 (CP30). The scheme is designed to provide revenue certainty and unlock investment, particularly for projects that may otherwise face barriers to deployment.

Ofgem's consultation document sets out the broader project assessment framework for the first LDES application window. It explains the multi-criteria approach being used to assess eligible projects, covering both quantitative and qualitative impacts—including socio-economic welfare, system benefits, and strategic value. NESO's CBA forms a key input to this process, alongside other assessments led by Ofgem and its appointed consultant. Stakeholders are invited to provide feedback on the proposed methodology to ensure the framework is robust, transparent, and fit for purpose.

## 1.1. Scope of document

This document outlines the proposed NESO methodology for conducting the CBA portion of the LDES Cap and Floor assessment. This takes the following structure:

- **Section 2**: Description of the core modelling capability used to model the impacts and benefits of the submitted projects.
- **Section 3**: Welfare and cost components considered for analysis, including descriptions for rationale of including or excluding components from the described scope.
- **Section 4**: Detailed modelling methodology, including required technical characteristics for eligible candidates, creation of the counterfactual, and methodologies for dealing with small capacity candidates/large application volumes.
- **Section 5**: Sensitivities to the core analysis which could be included within the scope.
- **Section 6**: Answers to previously raised queries from stakeholder groups regarding the methodology.

## 1. Introduction

This consultation sets out NESO's proposed approach to assessing the welfare and wider system benefits of LDES projects through detailed cost-benefit analysis. The results of this analysis will form a key input into Ofgem's broader project assessment, helping to compare and rank eligible projects based on their relative value. While NESO will not determine the overall procurement target or make funding decisions, our role is to provide robust, evidence-based insights that will inform Ofgem's decision-making process.

# 2. Model Background

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The LDES Cap and Floor Cost Benefit Analysis (CBA) will be based on the latest available Future Energy Scenarios (FES) 2025 pathways, which are expected to be published in July 2025. Using FES2025 will ensure that the assessment reflects the most up-to-date projections of generation, demand, gas and hydrogen use, European market interactions, and flexible demand assumptions. FES2025 also assumes a background level of battery storage, pumped hydro, Long Duration Electricity Storage (LDES), and hydrogen storage.

FES2025 will develop a range of pathways, with a narrower range up to 2030 compared to FES2024. The LDES Cap and Floor base assessment will be based on the Holistic Transition pathway. Security of Supply analysis will be undertaken separately using a single designated reference scenario.

Candidates will be assigned to one of two tracks based on their earliest available delivery date[1]. Track 1 projects will be assessed over the period 2030 to 2055, while Track 2 projects will be evaluated from 2033 to 2058. Within each track, all projects will undergo assessment during the same period, irrespective of their individual availability dates. However, the current Plexos energy market model simulates only up to the year 2044. To extend the analysis for the remaining years, the outputs from the final three modelled years will be averaged and utilised to extrapolate results for the subsequent years. This approach is consistent with previous Network Options Assessment analysis and provides a proportionate and pragmatic solution, given available data, and modelling timeline.

For the purposes of this assessment, Long Duration Electricity Storage (LDES) refers to energy storage systems capable of discharging at full rated power for eight hours or more[1]. These assets play a critical role in balancing supply and demand, particularly in a system with high levels of intermittent renewable generation. The background scenario already includes assumed future LDES deployment. To enable a robust Marginal Additional (MA) assessment, we require a background that does not already include projects under consideration, as this would risk double counting and distort the results. Therefore, as outlined in Section 4, some pre-2035 projects that have not yet reached a Final Investment Decision (FID) will be removed from the background scenario ahead of the assessment. Section 4 also sets out the method for forming assessment groups, designed to support clear articulation of the benefits associated with additional LDES capacity.

The base case for the LDES Cap and Floor Cost Benefit Analysis (CBA) will use a national pricing framework, consistent with current market arrangements. While the government has not yet made a final decision on whether the electricity market will transition to zonal pricing, this potential reform remains under active consideration as part of the Review of Electricity Market Arrangements (REMA). To account for this uncertainty, zonal pricing will

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[1] LDES Technical Decision Document: Long Duration Electricity Storage technical document | Ofgem

be modelled as a sensitivity, allowing us to explore the potential implications of locational pricing on the value of LDES. Zonal pricing would reflect regional differences in supply, demand, and network constraints, offering more granular price signals that could affect project revenues and system benefits.

Finally, the modelling of the Balancing Mechanism (BM) requires boundary capability constraints. As updated data will not be available in time for this analysis, inputs from the "Leading the Way" pathway from the Beyond 2030 publication will be used instead. This approach ensures that the assessment remains on track without introducing delay risks.

# 3. Cost and Benefit Components

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This section sets out the benefit components that NESO will assess as part of the Cost Benefit Analysis (CBA) for Long Duration Electricity Storage (LDES) projects. These components will inform Ofgem's Multi-Criteria Analysis (MCA) framework or will be constituents of the cap and floor revenue calculating.

## 3.1 Economic Assessment Input Components

All welfare and system impact figures will be presented as changes relative to the baseline, with positive values indicating benefits and negative values indicating costs. Contract for Difference (CfD) payments are treated as financial transfers between consumers and generators. While not a net system cost, they are considered an undesirable outcome from a consumer perspective and will therefore be reflected as a negative impact on consumer welfare, rather than included in total cost calculations.

### Consumer Welfare: Wholesale market costs

Wholesale market prices are a crucial component of consumer welfare. These prices are determined by the interaction of electricity supply and demand. Changes in wholesale market prices directly affect the costs of electricity for consumers. For the LDES cap and floor assessment, it is essential to evaluate how the integration of Long Duration Electricity Storage (LDES) impacts these prices. This involves analysing overall price changes for GB consumer electricity costs. Any reduction in wholesale market prices due to LDES could lead to significant cost savings for consumers.

### Consumer Welfare: Renewable (RES) support scheme costs

The Contract for Difference (CfD) scheme supports renewable and low carbon energy generators by guaranteeing a stable level of revenue through a pre-agreed strike price. If the wholesale market price is below the strike price, consumers top up the generator's revenues to the strike price level. Conversely, if the wholesale market price exceeds the strike price, generators pay back the excess revenues to consumers. The integration of LDES could impact the wholesale market prices and, consequently, the CfD scheme costs. These are captured as consumer welfare impacts.

### Consumer Welfare: Constraint management costs

The balancing mechanism costs of resolving network constraints will be calculated. Costs associated with the balancing mechanism are ultimately borne by consumers. The integration of LDES could influence these costs by providing additional flexibility potentially reducing the need for more expensive balancing actions. The output of this is a monetised value (£).

### Producer Welfare: Wholesale market costs

For producers of power in the GB market, revenue is primarily driven by wholesale market prices. The integration of Long Duration Electricity Storage (LDES) can influence these prices, impacting the gross margin for energy production. The gross margin is calculated as the revenues from electricity production less the costs of fuel and carbon emissions. If the addition of LDES leads to higher wholesale market prices, producers stand to benefit from increased revenues. Conversely, if LDES results in lower market prices, producers may experience a reduction in their revenues. Therefore, it is crucial to assess how LDES affects wholesale market prices and the subsequent impact on producer revenues, across all types of existing generators and storage (including existing BESS operators) within the GB market.

**Producer Welfare = Generator Welfare + Storage Welfare**

Impacts on existing BESS/storage operators will be calculated using the same methods required for LDES owner welfare (see subsequent section for details). Generator Welfare will be calculated by considering the margin for generation against operating costs.

### Producer Welfare: Interconnector Congestion Rent

This component captures the impact of LDES on interconnector congestion rents, which represent the economic value derived from electricity price differences between connected markets. Congestion rents are calculated as the product of interconnector flows and the price differential between the two market zones.

For the purposes of estimating GB welfare impacts, it is assumed that 50% of total congestion rents accrue to GB, which is consistent with previous approaches used in system modelling.

### LDES owner Welfare: Wholesale market arbitrage revenue

Arbitrage revenue will be calculated by post-processing PLEXOS modelling results to determine the cost of charging and the benefit of discharging (usually between periods of significant price disparity). This revenue stream is a key component of LDES profitability, as it captures the value generated from storing energy when prices are low and selling it when prices are high.

### System Impacts: Security of supply (cost of EENS using VoLL)

The contribution to security of supply of a technology depends on the expected demand, the weather, and the expected generation portfolio. As such, it is likely to change with time. In the case of LDES it will depend upon maximum power output, total energy stored and, to a lesser extent, round trip efficiency (RTE). The last factor dictates how fast LDES can recharge between two stress periods which are separated by a relatively short period of time.

The forthcoming Resource Adequacy in the 2030s publication expected summer 2025 will consider a number of scenarios. We expect that one of these scenarios will be chosen to act as a baseline for this analysis, albeit with all future uncommitted LDES/pumped storage removed.

A well-constructed reference scenario can be designed to be representative of typical or critical conditions, thereby ensuring that the assessment captures the essential dynamics of the energy system. By selecting a reference scenario that reflects a range of factors such as demand pattern and renewable energy generation we can ensure that the cost changes calculated are meaningful and applicable to real-world conditions. Using a single reference scenario to calculate cost changes in security of supply metrics is a robust and efficient method for assessing different LDES options. This approach ensures that the analysis is resource-efficient, clear, and focused on the most critical metrics.

The assessment will employ a Marginal Additional Methodology Approach, which evaluates the security of supply with and without individual LDES projects against a background scenario that includes potential LDES projects, providing insight into the marginal impact of each project within a fully integrated energy system. Projects will be grouped based on characteristics such as storage duration and efficiency but not location as our resource adequacy model excludes transmission. Within the group, the value will be apportioned to each project based on its total capacity.

There are many potential metrics for security of supply, but the one which most easily lends itself to incorporation into an economic evaluation is Expected Energy Unserved (EEU). This is a statistical average over many weather years and unplanned outage simulations within the model. It is proposed that this is calculated for 2030, 2035 and 2040 using the reference scenario. This benefit will then be interpolated and extrapolated to the remaining years. This can be combined with the Value of Lost Load (VoLL). The cost changes between reference and variant cases will represent the overall security of supply value of each project.

The output of this is a monetised value (£).

### System Impacts: Avoided renewable curtailment (not monetised)

Renewable curtailment volumes can be calculated from the model. This metric captures the extent to which LDES can help integrate renewable energy sources by reducing the need to curtail excess generation. By facilitating greater use of renewable energy, LDES projects can enhance the sustainability of the energy system. The monetisation of this would already by captured by the change in welfare or system costs. The output of this category would be a GWh value of curtailment. This would not be combined directly with the other monetary values in this assessment but provides a useful indication of change in system behaviour as a result of LDES project integration.

### System Impacts: System Operability

System operability and the provision of ancillary services—such as frequency response, reserve, reactive power, and stability—are important considerations in assessing the overall value of LDES technologies. While NESO will not include operability-related benefits in the Cost Benefit Analysis (CBA), we acknowledge that these services may represent a significant revenue stream for some technologies, particularly those with lower round-trip efficiencies that may place less emphasis on arbitrage.

In this context, ancillary service value cannot be discounted entirely from the overall assessment. However, there are major uncertainties in forecasting future ancillary service revenues. These services are procured via competitive tenders, subject to changing technical requirements and pricing structures, and winning contracts depends on market conditions and asset capabilities at the time of delivery. NESO cannot assess or rely on project-specific cost or bid assumptions that may be commercially sensitive or speculative.

To reflect this, applicants will be expected to provide their own view of potential ancillary service revenues as part of their Project Assessment submissions. NESO will support Ofgem by providing input into the design of the pro-forma submission template and will contribute to the qualitative assessment of these submissions—particularly in evaluating technical claims and consistency with current system needs.

While NESO will not model system operability benefits directly in the CBA, our technical expertise will continue to inform the broader evaluation process to ensure ancillary services potential is captured in a proportionate and credible way.

### Wider economic and social impacts: Unpriced Carbon Externality Cost

Emissions will be calculated based on PLEXOS modelling. The societal value of carbon emissions will be calculated from this Green Book central value series. This approach ensures that the environmental impact of LDES integration is quantified in terms of CO2 reductions, contributing to the overall assessment of societal benefits. The output of this is a monetised value (£).

## 3.2 Total System Cost Components

For completeness, we will also estimate total system costs—while these figures inform cap-and-floor considerations, they do not contribute to welfare benefits. The total system cost calculation will comprise the following components:

### Generation Costs

These are calculated based on the short run marginal cost of the plant and the generation output from the plant in each period. The short run marginal cost includes fuel costs, efficiency, and variable operating and maintenance costs.

### Carbon Costs

These are the extra carbon costs not included in the market price, calculated from the societal value of carbon emissions from the Green Book central value series.

### Interconnector Costs

Interconnector costs need to take account of the cost of power imported, as well as the value of exporting power to other regions. These costs are based on flow and region price, with 50% of the total value assumed to account for variable interconnector ownership and whether power is bought or sold into other markets.

Network costs for connecting Long Duration Electricity Storage (LDES) projects to the grid will not be considered because many options have not yet completed the full connection application process due to ongoing connection reform. The impact on the need for wider reinforcements will not be explicitly assessed, however the impact on balancing mechanism costs will be evaluated as a proxy for this.

# 4. Further details on method for undertaking the assessment

# 4. Further details on method for undertaking the assessment

In this section, we outline the methodology for conducting the Cost-Benefit Analysis (CBA) for Long Duration Electricity Storage (LDES) projects. Our approach employs a Marginal Additional (MA) method to quantify the benefits of individual LDES projects against a background with other LDES Cap & Floor (C&F) applicants. This method enables detailed analysis of individual project benefits, while maintaining a fair and transparent assessment.

## 4.1 Technical Parameters that would be needed for modelling in Plexos

LDES participants are required to submit detailed technical parameters for their projects to enable accurate setup and modelling in Plexos. These parameters must comprehensively represent the LDES plant and include, but are not limited to, the parameters described in this section.

Technical input parameters for all LDES technology types other than pump storage:

- **Location:** The point on the network where the plant will connect. This will be specified as a latitude and longitude.
- **Rated Discharge Power (MW):** Maximum rated power at which the plant can be continuously discharged.
- **Rated Charge Power (MW):** Maximum rated power at which the plant can be continuously charged.
- **Storage capacity (MWh)**: Total theoretical energy storage capacity of the plant in MWh. This can be calculated from the minimum duration if that is provided instead.
- **Charge Efficiency**: Charge Efficiency is the ratio of power stored in the storage to the load on the grid, including any losses such as inverter losses.
- **Discharge Efficiency**: Discharge Efficiency is the ratio of power sent to the grid to the total power discharged from the storage, including any inverter losses.
- **Min SoC %:** The minimum allowable state of charge for the battery, expressed as a percentage of total storage capacity. This represents the lowest energy level the system can reach during operation, below which it cannot discharge further. *Example: 10%*
- **Max SoC %:** The maximum allowable state of charge for the battery, expressed as a percentage of total storage capacity. This represents the upper limit of energy the system can store before it must stop charging. *Example: 95%*
- **Max Ramp Up:** The maximum rate at which the plant can increase its power output (discharge) from one time step to the next, expressed in megawatts per minute.

- **Max Ramp down:** The maximum rate at which the plant can decrease its power output (discharge) or charging input, expressed in megawatts per minute.
- **Cycle Lifetime**: Number of cycles the plant can do before it is deemed to be due for replacement. This will be used to calculate a daily cycle limit.
- **Operational Constraints**: Minimum and maximum states of charge.
- **VO&M cost**: Variable operating and maintenance cost per megawatt-hour of energy discharged. This should include the cost of any fuel used during operation, if applicable (e.g. for hybrid CAES systems).
- **Technical and Economic Life**

Technical input parameters for pump storage plants:

- **Location:** The point on the transmission network where the plant will connect.
- **Rated Discharge Power (MW):** Maximum rated power at which the plant can be continuously discharged.
- **Rated Charge Power (MW):** Maximum rated power at which the plant can be continuously changed.
- **Efficiency**: Efficiency is the round-trip efficiency of the pump storage generator expressed as a percentage.
- **Head storage**: Total storage capacity of header lake (MWh).
- **Tail storage**: Total storage capacity of tail lake (MWh).
- **Shared Head Lake:** If the head (upper) reservoir is shared with other projects, please list the names of all associated projects. Each name must match either the official applicant name as submitted in their application or the name of the existing plant.
- **Shared Tail lake:** If the tail (lower) reservoir is shared with other projects, please list the names of all associated projects. Each name must match either the official applicant name as submitted in their application or the name of the existing plant.
- **Max Ramp Up:** The maximum rate at which the plant can increase its power output (discharge) from one time step to the next, expressed in megawatts per minute.
- **Max Ramp down:** The maximum rate at which the plant can decrease its power output (discharge) or charging input, expressed in megawatts per minute.
- **VO&M cost**: Variable operating and maintenance cost per MWh.
- **Technical and Economic Life**

## 4.2 Marginal Addition (MA) Method

This section outlines the methodology for evaluating the impact of Long-Duration Electricity Storage (LDES) projects through the formation of a balanced counterfactual. The process begins with a base system model aligned to a Future Energy Scenarios (FES) pathway. From this, non-Final Investment Decision (non-FID) LDES projects are removed to define a neutral baseline. A notional LDES plant is then modelled in all 37 transmission zones to represent the capacity that was removed.

### 4.2.1 Formation of Counterfactual for the Assessment

To ensure consistency, objectivity, and resilience to scrutiny, a static counterfactual will be applied across all assessments. This eliminates the need to construct bespoke comparison groups for each LDES application and enables robust comparison on a like-for-like basis.

The counterfactual is created using the following steps:

1. **Remove non-FID LDES projects**: All LDES projects without a Final Investment Decision are excluded from the FES2025 scenario, in line with the baseline definition in Section 3. This avoids double-counting and ensures only committed projects are reflected in the base case.
2. **Insert a notional archetype**: A standardised LDES plant is modelled in each of the 37 Plexos transmission zones. This archetypical plant acts as a generic stand-in for the capacity that has been removed.
3. **Equal capacity allocation**: The total removed LDES capacity is divided equally among the 37 zones. This equal distribution avoids introducing geographic or technological bias and ensures a system-neutral foundation.

This configuration—removing uncommitted LDES projects and replacing them with a uniformly distributed archetype—serves as the common reference case for all project assessments. When an LDES application is assessed, it is added to this counterfactual to determine its marginal impact. In most cases, this will result in a total system LDES capacity that slightly exceeds the original amount removed. This is intentional, enabling the added value of each application to be measured against a fixed and impartial benchmark.

By avoiding bespoke grouping, this method ensures fairness across assessments, enhances transparency for stakeholders, and simplifies interpretation of the cost-benefit analysis (CBA) results.

### 4.2.2 Assessment

The Marginal Addition method assesses the specific contribution of each LDES project by comparing two modelled scenarios:

- **Counterfactual scenario**: As described above, this scenario includes the evenly distributed notional LDES plants but excludes the project being assessed.

- **Factual scenario**: The same model is re-run with the assessed project added to the system.

For each project, welfare components and system impacts—outlined in Section 3—are calculated under both scenarios. The difference between the factual and counterfactual results represents the project's marginal benefit.

## 4.3 Cluster grouping of LDES applicants

To ensure the cap and floor assessment process remains efficient and fair when faced with a high volume of applicants, we propose a minded-to approach that allows for the grouping of smaller capacity projects under certain conditions. Specifically, if more than 50 projects proceed through eligibility, grouping of projects below a flexible capacity threshold (provisionally 300 MW) may be applied. A maximum group size of 600 MW is also provisionally proposed. These parameters are minded-to positions and will be finalised during the grouping process, once the full set of applicant data is available to inform sensible and proportionate groupings.

Grouping is necessary to avoid analytical inefficiencies and potential crowding out of smaller but viable projects. Without grouping, a large number of small projects could disproportionately burden modelling resources and risk being deprioritised due to computational constraints. Grouping ensures that such projects can still be assessed and valued appropriately within the system modelling framework. Groups may include projects from multiple zones where there are no boundaries that would significantly affect dispatch or system outcomes.

Projects below the threshold will be grouped by connection zone and jointly assessed in a single sensitivity run. For example, if five projects — 100 MW, 100 MW, 50 MW, 120 MW, and 150 MW — are proposed within the same region (e.g., East Anglia), they would be combined into one grouped sensitivity. Within this grouping, each project remains individually modelled, allowing project-specific behaviours and operational characteristics to be retained and examined.

Although the group is assessed collectively, benefits will be allocated to individual projects on a pro-rata basis, based on each project's share of the total capacity in the group. This ensures that grouping does not distort individual valuations and avoids favouring larger applicants at the expense of smaller ones — directly addressing the risk of crowding out.

Projects will be randomly assigned to each group, and grouping parameters (e.g. group size limits and thresholds) will be adjusted so that the number of grouped projects remains in the range of 50 to 100, supporting both modelling tractability and fair representation. Initial attempts will be made to reduce the project/group number below a threshold denoted as $N_1$ – a backstop value of $N_2$ groups will be applied if grouping is not possible to the level of this threshold. This approach allows for some flexibility in how grouping of projects is applied, while bounding the overall modelling problem within an acceptable range.

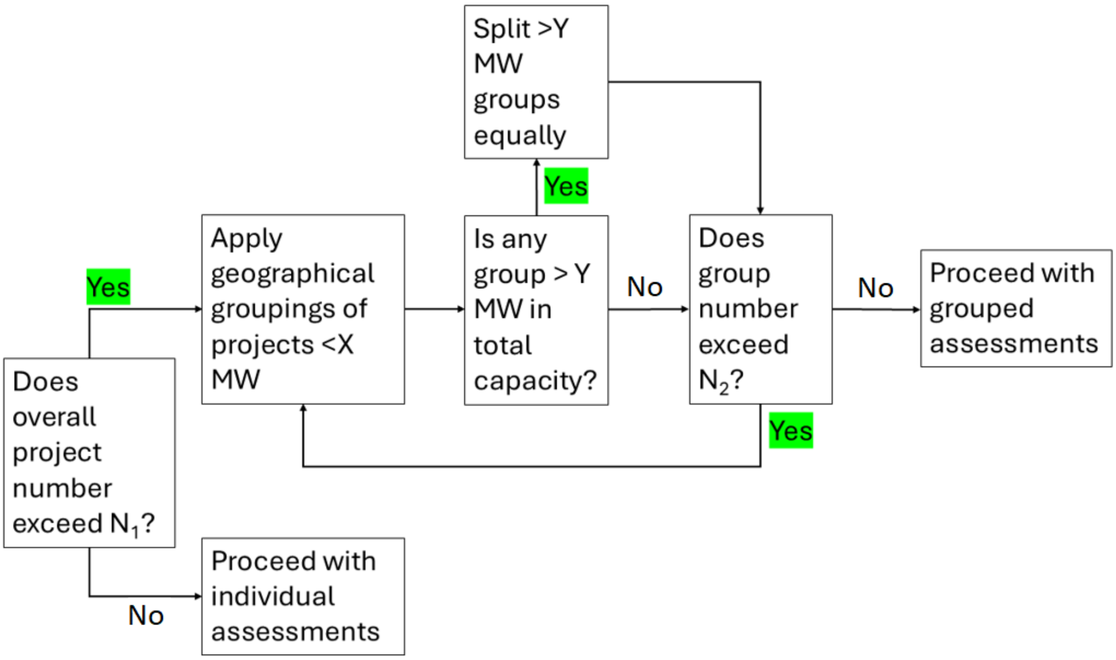


*Figure 1. Shows cluster groupings approach*

## 4.4 Additional Considerations

In line with Ofgem's Technical Decision Document[1], several additional considerations are relevant to how LDES projects will be assessed. Ofgem has proposed a twin track approach to manage projects with different delivery timelines: Track 1 for those deliverables by 2030, and Track 2 for those deliverables by 2033. Projects are also categorised into two streams based on technology maturity, with Stream 1 covering fully commercial technologies (TRL 9) and Stream 2 covering emerging or near-commercial technologies (TRL 8). The following considerations expand on how these policy structures are reflected in the assessment methodology.

**Assessment Tracks**: The Plexos modelling approach is neutral to the twin track approach as outlined in Ofgem's TDD. However, the benefit calculation horizon depends on the track[1] (2030 or 2033), as defined in the introduction section.

**Technology Readiness Levels (TRL):** All projects will be evaluated uniformly, regardless of whether they are at TRL9 (stream 1) or TRL8 (stream 2). The assessment will be determined primarily by the configuration of each LDES plant in Plexos, which will be tailored based on the specific parameters provided for each project. This includes techno-economic parameters and locational information.

**Comprehensive Evaluation:** The assessment will result in a detailed compilation of component benefits for each project. This will facilitate Ofgem in performing a Multi-Criteria Analysis (MCA) to rank the projects.

# 5. Sensitivities

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Sensitivities can be used to provide evidence of project benefit under varying conditions. This creates a more robust understanding of the benefit that can be achieved from the LDES projects submitted than using only the base set of conditions for assessment.

The base case will use the FES Holistic Transition (HT) scenario, which presents a balanced view of the UK's energy future aligned with current policies and trends. It serves as a reference scenario, capturing a plausible trajectory for energy supply and demand while accounting for decarbonisation goals, technological progress, and economic growth. This pathway provides a realistic framework to support informed decision-making and strategic planning.

### Sensitivity: An additional Future Energy Pathway

FES pathways explore varying generation and demand balances driven by key policy choices and technology developments. They provide a foundation for assessing how different energy futures affect the value of LDES, particularly under varying levels of ambition in the electricity sector and differing availability of competing storage and flexibility options.

We propose to model one additional FES pathway beyond the central case, to capture a broader range of potential system outcomes.

### Sensitivity: Zonal

Zonal pricing will be explored as a sensitivity to assess the impact of locational price signals on the value of LDES. By reflecting regional variations in supply, demand, and network constraints, zonal pricing introduces more granular market signals. This can significantly influence project revenues and highlight where system benefits from LDES may be most pronounced. This sensitivity will be assessed relative to the base case. If a clear policy decision is taken not to pursue zonal pricing, then this sensitivity will be dropped.

### Sensitivity: Weather Years

NESO's standard dispatch modelling is based on the 2013 weather year, selected for its representative mix of conditions, offering a reasonable stress test across technologies. However, capturing system behaviour under more extreme weather patterns may provide valuable insights into the resilience and performance of LDES under varying renewable output profiles.

We propose modelling two additional weather years—1985 and 2010—on the central FES pathway to evaluate LDES benefits under different meteorological extremes:

1985: A Dunkelflaute year, with prolonged periods of low wind and solar generation.

2010: Characterised by a stormy winter and multiple high-wind events.

2013: Serves as the baseline, with a mix of cold spells and milder conditions.

This sensitivity will be assessed relative to the base case.

In the event that a high volume of LDES applicants must be assessed through the CBA, NESO reserves the right to limit the scope of sensitivities listed in this section. Further optional sensitivities, as outlined in the annex, will be undertaken only if sufficient time and resources remain after completing the primary assessments. This approach ensures that the analysis remains focused, efficient, and aligned with available capacity.

# 6. Stakeholder Questions and Clarifications

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This section responds to key questions raised by stakeholders to support a clear understanding of the assessment process. We appreciate the valuable feedback received before and during the LDES workshop. While not all points could be addressed here, many are reflected in the responses below. All input has been carefully considered and will continue to shape the final framework.

## 6.1 Modelling Assumptions

Q: What counterfactual will be used to assess submissions, and how will competing technologies be treated (e.g., OCGTs, DSR, other storage, interconnectors)?

A: The counterfactual will use assumptions from the Future Energy Scenarios (FES) 2025. Competing technologies will be modelled as either specific named plants or generic types where necessary. Technical characteristics (e.g., efficiency) will be derived from real-world data wherever available.

Q: What assumptions are made about interactions with other network and generation assets?

A: Interactions will be modelled using Plexos, simulating energy storage, arbitrage, and operational impacts across the power system. Producer and storage operator welfare components will be explicitly quantified for each project.

Q: How will assumptions on zonal versus national electricity pricing be handled?

A: If government confirms zonal pricing by 1 September 2025, the assessment will use zonal prices. Otherwise, national pricing will be used.

Q: Can you explain how the model will take account of the physics of the system, not just treat all constraints as thermal?

A: The model accounts for not only thermal constraints but also voltage and stability constraints, all informed by detailed power systems analysis. This ensures that network limitations reflect real-world physics, supporting a more accurate and robust assessment of each project's impact.

Q: How will the model account for the stochastic/probabilistic nature of the storage problem under imperfect information (as opposed to the perfect-foresight cost minimisation used by PLEXOS, typically)?

A: With the large volume of applications, a fully stochastic optimisation is out of scope for this analysis. Instead, PLEXOS is run using rolling perfect-foresight blocks, where perfect foresight is only assumed within each optimisation step—not across the full time horizon. To reflect uncertainty, the model incorporates multiple weather-year simulations and other sensitivity runs. This approach provides a practical and scalable way to capture key sources of variability without the computational burden of full stochastic modelling.

Q: How will the model address the well-known concerns that cost-minimisation models like PLEXOS do not generate realistic prices?

A: No model produces actual or near-actual market prices—models are abstractions of reality. PLEXOS is used to simulate dispatch and system operation under consistent assumptions, not to forecast precise prices or revenues. The purpose of the modelling is to enable a fair, comparative assessment of projects. As such, the outputs are used to rank projects based on relative system value, not to predict exact market outcomes. This approach ensures consistency and transparency in evaluating the incremental benefits of each LDES project.

Q: How will the model address the potential investment in the grid to account for constraints that emerge on the system and reduce costs?

A: The model incorporates the impact of planned grid investments as published in NESO's Beyond 2030 report. These investments are reflected in the boundary capability assumptions used in the CBA. While the model does not dynamically optimise future transmission build-out, it captures the benefits of already-identified reinforcements, ensuring that constraint-related costs and system flexibility are assessed in a realistic future network context.

Q: How will the model take account of different levels of storage penetration. (In the case of interconnectors for the cap and floor, Ofgem assumed that all interconnectors were built when valuing benefits to society. That clearly won't work if one assumes all applicant storage is built because the benefits will be self-cannibalised)?

A: Determining an adequate counterfactual is a balance between consistency, deliverability, and transparency—there is no perfect solution. The NESO consultation document sets out the most pragmatic approach to meet these principles. All LDES projects are assessed individually (or in small clusters) against a common counterfactual that excludes all non-FID LDES. This avoids assuming that all applicants are built and ensures that mutual cannibalisation is internalised within each project's marginal benefit calculation. This method avoids overstating system value and allows for fair, like-for-like comparison across projects.

## 6.2 Cost and Revenue Assumptions

Q: How will revenue stacking (wholesale, capacity, ancillary markets) be modelled?

A: Revenue stacking across wholesale, capacity, and ancillary service markets falls outside NESO's scope for this assessment. NESO's role is limited to quantifying the specific benefit components outlined in this document. A full evaluation of revenue interactions across multiple markets will be undertaken separately by Ofgem or other relevant parties as part of the broader cap and floor regime assessment.

Q: How will Cap and Floor payments (consumer costs) be assessed probabilistically?

A: This is outside NESO's scope; handled by Ofgem at a later stage.

Q: What discount rate will be used?

A: A 3.5% real discount rate, consistent with HM Treasury's Green Book guidance.

Q: Why 50MW or 100MW capacity threshold has been applied instead of MWhr capacity? As some long duration technology like Iron Flow can deliver 800MWhr while installing 8MW of Iron Flow Batteries...

A: The MW threshold ensures projects can deliver meaningful system impact in terms of power output, which is critical for having sufficient impact on the system. While high-MWh, low-MW technologies offer long duration, their limited dispatchability reduces their value in meeting peak demand. The thresholds also help manage assessment resources.

Q: On the Marginal additional approach – is it not there a catch-22 on the method? How can you include FID/ non-FID projects - when all these projects rely on the Cap and Floor to achieve FID. Aren't all projects "non-FID" until Q2 2026?

A: In modelling terms, "non-FID" refers to projects that had not reached Final Investment Decision at the time the FES scenarios were developed. These may be real or placeholder projects. To avoid double-counting, all non-FID LDES is removed from the background scenario before assessing applicants. This creates a neutral baseline, ensuring each project is assessed on its marginal value without assuming the system is already saturated with storage.

Q: Please define non-FID LDES and confirm source of information feeding into this

A: Non-FID LDES refers to Long Duration Electricity Storage projects that have not yet reached Final Investment Decision (FID). These include both real projects that are under development and placeholder projects used to represent expected future capability in the system. NESO will determine which projects are considered non-FID based on a range of data sources, including project submissions, market intelligence, and scenario assumptions.

## 6.3 Project Evaluation and Comparison

Q: Will Stream 1 and Stream 2 projects directly compete?

A: Both streams will be assessed concurrently, with Stream 2 projects not disadvantaged if they show superior characteristics.

Q: How will discharge duration affect project evaluation?

A: Longer discharge duration (e.g., 20 hours vs 8 hours) will be evaluated within the overall trade-offs between system value and cost.

Q: Will earlier start dates (e.g., 2028 vs 2030) receive preference?

A: No. Projects are assessed on total system value, not earliest operation date.

Q: How will asset location relative to network constraints be assessed?

A: Location will be modelled in Plexos, capturing impacts of being ahead or behind boundary constraints.

Q: How will cost maturity be assessed?

A: While cost maturity is considered at the eligibility stage, it will not directly affect the CBA conducted by NESO.

Q: How will degradation and maintenance costs be accounted for?

A: This aspect falls outside NESO's scope for this assessment.

Q: Will longer duration projects (e.g. 15 hours vs 8 hours) be favoured? How will the additional benefit of additional duration be quantified? A longer duration project will naturally need a higher cap and floor than meeting the minimum requirements.

A: The benefit of longer duration projects will be assessed through the system modelling. Projects with greater discharge duration may offer enhanced flexibility and resilience, which could translate into higher system value. However, this will be evaluated on a case-by-case basis within the modelling framework.

Any additional benefit from longer duration will be weighed against the project's capital and operational costs, with the overall value assessed on a net present value (NPV) basis. While longer duration may increase benefits, it may also increase costs—both factors will be considered in the CBA.

## 6.4 Technical Characteristics and Operational Performance

Q: What technical parameters (e.g., efficiency, reliability) will be considered?

A: Technical characteristics such as round-trip efficiency will be considered. Operational risk is addressed during feasibility screening, not directly weighted during CBA.

Q: Will storage assets always be assumed to discharge over 8+ hours?

A: No. The model optimises operation. Some cycles may be shorter depending on market conditions.

Q: What temporal granularity will the model use?

A: The modelling will use a 3-hourly resolution.

Q: How will representative operating profiles be captured?

A: A range of conditions (seasonality, weather, system needs) will be used to test different outcomes.

## 6.5 Sensitivities and Other Considerations

Q: What scenarios and sensitivities will be used?

A: An additional (FES) pathways will be used, alongside selected sensitivities such as weather variability, and zonal pricing.

Q: How will refurbishment projects be assessed?

A: Refurbishment projects will be assessed using the same approach as new LDES projects.

Q: How will embedded carbon from construction be assessed?

A: Embedded carbon is outside the scope of NESO's CBA.

Q: How will "hard-to-monetise" impacts (e.g., environmental and community impacts) be considered?

A: Hard-to-monetise impacts are outside NESO's scope for this CBA.

Q: How will the model take account of different scenarios for the evolution of the system?

A: The base assessment uses the 2025 FES Holistic Transition pathway; an alternative FES pathway plus zonal-pricing and extreme-weather sensitivities are plannedto test robustness across credible futures.

# Annex 1: Alternative Assessment Method:

## Annex 1: Alternative Assessment Method

In addition to the previously described Marginal Addition Method, we considered two alternative assessment methods for Long Duration Electricity Storage (LDES) projects assessment. Despite their merits, these approaches were not adopted for the reasons outlined below.

**Alternative Approach 1: Capacity Expansion Modelling**

This approach involves a two-stage capacity expansion modelling process.

Stage 1: non-FID LDES are excluded from the base model, and all LDES candidates are included as potential expansion candidates. A capacity expansion model (CEM) is run to identify which LDES candidates should fill the LDES gap, resulting in an optimal build out of LDES serving as a reference for the second stage of the assessment.

Stage 2: The goal of the second stage is to quantify the value of each LDES C&F candidate. Here, multiple capacity expansion models (hereafter referred to as counterfactual models), one for each LDES C&F candidate, are created and run. In each model, the C&F candidate corresponding to that model is marked as "Must Build" or "Must not Build", depending on whether it was built in the first stage. LDES C&F candidates built in the first stage are marked as "Must not Build" and those not built are marked as "Must Build". The difference between the total system costs of the factual model and each counterfactual model, denotes the benefit of the C&F candidate corresponding to that counterfactual model.

This approach has the advantage of preserving the economic integrity of the base model used in the assessment by avoiding model distortions associated with storage capacity imbalance. However, it requires substantial computational resources due to extensive modelling, and may, therefore, result in a longer assessment period. Furthermore, preliminary results from ongoing studies within NESO indicate that this approach may not be suitable for the type of assessment being undertaken. Moreover, it does not allow the calculation of the individual welfare components against which each LDES, candidate is assessed. Finally, it may rely on externally determined build LDES limits, to prevent the over or under building of LDES. While this is not necessarily a bad thing, it is not clear how these limits can be determined, rendering the approach prone to unrealistic assumptions regarding the amount of LDES built.

**Alternative Approach 2: Capacity Expansion Modelling with Manual Adjustment**

In this approach, the assessment will follow a two-stage CEM process, to fairly evaluate the value of LDES projects against a credible system counterfactual.

**Stage 1: Baseline System Cost Assessment**

First, non-FID LDES projects from list of potential candidates will be removed from the system background. A Capacity Expansion (CEM) model run will then be performed, allowing other technologies to substitute for the removed capacity. This establishes baseline system costs, representing the maximum cost to consumers in the absence of additional LDES deployment.

**Stage 2: LDES Candidate Selection and System Cost Adjustment**

Here, all LDES applications are included as expansion candidates alongside "generic LDES projects" that can only be commissioned post 2035, up to the capacity limit set in the original FES scenario. Care will be taken to ensure that cost and commissioning assumptions for generic units avoid distorting the timing of investments. If the LDES capacity that gets built between 2030 and 2035 is below the indicative range set by DESNZ and NESO and system costs are lower than the baseline obtained in Stage 1, the model will be manually forced to build additional LDES up to the point of system cost equality with the baseline (or even beyond if it's agreed that wider benefits are significant). The selection criteria for project prioritisation during manual adjustment may include levelized cost of storage, technology type, location, and other project categorisation criteria. Additional stages may be required for more detailed system cost information, with project grouping to reduce the modelling burden.

This approach has the same merits as the first alternative approach described earlier in this section but with the additional merit of not requiring the explicit definition of LDES capacity build limits, and reduced number of CE runs. It also allows for a slightly suboptimal (in cost terms) LDES capacity to be built in return for other non-cost system, as well as societal benefits. However, it shares many of the demerits of the first alternative approach, except for the need to define explicit LDES capacity build limits. Furthermore, the manual LDES capacity addition militates against its transparency and deliverability and renders the approach difficult to communicate to stakeholders.

**Alternative Approach 3: Use Marginal Additional approach described in this consultation document, but with formation of multiple counterfactual assessment groups.**

An alternative method considered during development was to retain the Marginal Addition (MA) framework but implement it using *multiple counterfactual assessment groups* instead of a single, static counterfactual. The idea behind this approach was to increase the representativeness of the system background by tailoring groupings of LDES applicants based on their characteristics. However, due to the added complexity, difficulty in justifying group formation, and reduced transparency, this method was not taken forward.

**Method Overview**

This approach starts from the same base model described in Section 3, using the FES2025 or FES2024 scenario with the removal of all Long Duration Electricity Storage (LDES) projects that lacked a Final Investment Decision (FID) before 2035.

Given the uncertainty around how much capacity will apply to the cap and floor scheme, the method was designed to handle a range of application volumes. Three cases were considered:

**Case 1: Total applicant capacity exceeds removed non-FID LDES capacity**

In this scenario, LDES applicants would be divided into several assessment groups. Each group would then be assessed using a dedicated counterfactual in which only that group is added to the system, restoring a capacity level close to the amount previously removed. A small buffer could be allowed to enable practical group formation.

To ensure comparability and fairness, projects would be allocated to groups in a way that maximised diversity across three dimensions: location (based on Plexos transmission zones), technology class (e.g. pumped hydro, lithium-ion, flow, compressed air), and size band (small, medium, large). The grouping process aimed to ensure that no group was dominated by a particular region or technology, and that diversity was balanced between groups to avoid bias in the comparative results.

**Case 2: Total applicant capacity is less than removed non-FID LDES capacity**

In this less likely scenario, all applicant projects would be assessed as a single group. Any remaining capacity shortfall would be made up by adding back notional non-FID LDES to bring the overall capacity in the model up to the level of the original FES scenario.

**Case 3: Non-FID LDES capacity is negligible compared to total applicant capacity**

If the amount of LDES capacity removed from the background is small—less than 10% of the total volume of applications—a single static counterfactual would be used. In this case, the system would be considered sufficiently rebalanced simply by adding each individual project during assessment.

**Why This Approach Was Not Taken Forward**

Although this method had the potential to create more representative background scenarios, it introduced considerable additional complexity. Group formation required balancing multiple criteria and could be perceived as subjective or difficult to justify to stakeholders. It also posed a risk to transparency and repeatability, making it harder to explain or audit the assessment process. The adopted approach—using a single, static counterfactual with an archetypical LDES plant distributed evenly across the system—was judged to offer a more robust, transparent, and defensible framework for marginal assessment.

**Concluding Remarks**

Each of the alternative methods considered was intended to enhance the assessment of LDES projects by introducing different forms of optimisation, flexibility, or system realism. While they offered some theoretical and practical advantages, all were found to introduce significant challenges—ranging from excessive modelling burden and reduced transparency to difficulties in stakeholder communication and replicability.

After careful evaluation, these approaches were not adopted. The Marginal Addition Method, as set out in the main consultation document, was selected as the primary assessment approach due to its balance of rigour, transparency, and deliverability. It provides a consistent, scalable, and fair framework for quantifying the benefits of individual LDES projects and is well suited to the regulatory and analytical context of the cap and floor scheme.

# Annex 2: Optional Additional Sensitivities

# Annex 2: Optional Additional Sensitivities

The following optional sensitivities will be included in the analysis if time and resources permit. These scenarios offer extra insight into LDES under different market and system conditions but are less critical than core assessments. They allow NESO to capture more outcomes if capacity permits. If performed, these sensitivities will use the base scenario.

**Sensitivity: High Demand Side Response Technologies**

This scenario examines the effect of widespread and effective deployment of demand-side response (DSR) technologies, including both demand shedding and shifting. High levels of DSR may reduce the overall need for LDES by offering alternative sources of system flexibility. This sensitivity will be modelled on the central FES pathway to isolate its impact on welfare and system value.

**Sensitivity: High Gas Prices**

This sensitivity explores how elevated gas prices could affect electricity system outcomes. Higher gas prices raise generation costs and shift dispatch patterns, which may increase the value of low-carbon, non-gas-dependent flexibility solutions like LDES. As with the DSR sensitivity, this will be modelled on the central FES pathway to provide a clear comparison with the base case.

**Sensitivity prioritisation list**

The table below summarises all sensitivities from the main document, including the optional ones outlined in this annex. It also indicates their prioritisation, which will guide which sensitivities may be excluded if time or resource constraints arise.

| Priority Number | Sensitivity name |
|---|---|
| 1 | Base Run: Central Future Energy Pathway |
| 2 | Additional Future Energy Pathway |
| 3 | Zonal |
| 4 | Weather Year 2010 |
| 5 | Weather Year 1985 |
| 5 | High Gas Prices (optional) |
| 6 | High Demand Side Response (optional) |