Decision

Financial Framework: LDES Window 1 Cap and Floor regime

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Following the Consultation on LDES Financial Framework for Window 1 Cap and Floor (C&F) regime, we have now concluded the review of stakeholder feedback on the proposed Financial Framework. This decision document summarises the responses to the consultation, describes our consideration of those responses and our further analysis, and provides our final decision on the Financial Framework.

The final Cap and Floor Financial Model (CFFM) and handbook, which will support consistent application of the framework and inform Project Assessments (PAs), will be published following this decision. We set out the information that eligible LDES projects (Projects) will need to provide to enable us to carry out the PA. This decision marks a key milestone in the implementation of the first Long Duration Electricity Storage (LDES) C&F regime, designed to accelerate investment in flexible, low-carbon energy infrastructure aligned with the Clean Power 2030 target.

References to the "Authority", "Ofgem", "we", and "our" are used interchangeably in this document. The Authority refers to GEMA, the Gas and Electricity Markets Authority. The Office of Gas and Electricity Markets (Ofgem) supports GEMA in its day-to-day work.

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Executive summary

Ofgem has completed its Consultation on the Financial Framework for Long Duration Electricity Storage (LDES) Projects applying under Window 1 of the Cap and Floor (C&F) regime. This decision responds directly to the further actions set out in the Technical Decision Document (TDD), published in March 2025, and incorporates stakeholder feedback to refine our approach. The final framework is designed to support timely investment in LDES technologies, deliver value for consumers, and maintain regulatory certainty. It also aligns with the UK Government's Clean Power 2030 target and Ofgem Forward Work Programme 2025/26.

Purpose and scope

This document sets out our decision on the Financial Framework for LDES Projects applying under Window 1 of the C&F regime. It follows our consultation published on 19 June 2025, which sought views on the proposed Financial Framework.

What stakeholders said

Preference for an administrative approach – Whilst there was general support for the principle of competition, a significant number of stakeholders advocated for administratively set C&F levels, stating that this approach would enable a better focus on the strategic and economic assessments, while also avoiding the pitfalls of speculative competition. Competitive bidding on a range of uncertain parameters was seen to increase the risk of undeliverable projects.

Concerns about proposed incentives - There was widespread support for the Minimum Availability Target (MAT) and performance-linked incentives, but many stakeholders deemed the structure to be overly penal. The 10% revenue sharing above the cap, was cited as being too low especially when compared to international comparators, Australia's Long-Term Energy Service Agreements (LTESA) at 50% was widely mentioned. There was broad consensus that the enhanced revenue sharing for the 25% most competitive bids could increase the likelihood of gaming. Stakeholders noted that it may encourage strategic underbidding, potentially leading to undeliverable proposals and undermining the credibility of the process.

Financial risk and investability - Stakeholders highlighted issues around uncertainty in financing, a cost of capital perceived as too low and the need for increased investor confidence. Stakeholders stressed the need for the framework to be bankable and support long-term investment, with multiple stakeholders suggesting the need for first of a kind (FOAK) uplifts. The lack of clarity surrounding post-regime mechanisms, in particular enduring clawbacks and soft caps, is seen to be detrimental to securing investment in the LDES regime.

Inflation and indexation - The proposed 2% fixed inflation indexation was a source of concern with many stating that this would introduce basis risk and suggested indexing to outturn inflation.

Need for technology differentiation - LDES covers a wide range of technologies, many of which are new to the GB energy system or have not been built in GB for decades. Around half of the stakeholder responses called for technology-specific treatment within the framework, highlighting differences in risk profiles, lifespans, and operational characteristics. They suggested these should be reflected in other areas of the framework such as financial assumptions, performance metrics, C&F setting.

Financial resilience & BSUoS – Stakeholders broadly supported measures to ensure financial resilience and favoured using BSUoS charges as the mechanism to fund C&F payments. This means that payments to Projects under the C&F regime would be recovered through balancing services charges.

Ofgem's response

The role of competition – The number of financial parameters that Projects can bid on has been reduced from five to two: regime duration and residual value.

Incentive structure - The extra revenue-sharing incentive for the 25% most competitive bids has been removed. Instead, all Projects will now receive a greater share of revenue above the cap, with the rate increasing from 10% to 30%. Changes have also been made to cost and delivery incentives. All economic and efficient costs will be added to the Regulatory Asset Value (RAV), helping ensure Projects are fairly funded. The two-year backstop on delivery dates due to force majeure remains in place, meaning Track 1 and Track 2 Projects must be delivered by 2032 and 2035, respectively.

Financial risk and investability - We believe the updates we have made following consultation will reduce financial risk and improve investability in the LDES C&F regime. Overall we consider that the LDES C&F regime, including both the cap and floor levels we have decided to use, represent a strong and investable package. The C&F regime is designed to provide a sufficient **downside return** to facilitate investment, not to serve as a target return. Projects will be able to request a higher floor rate via a regime variation, however this must be supported by strong quantitative evidence and show clear consumer benefits.

Inflation - We have revised our approach to inflation, moving from a fixed to an outturn inflation indexation method for C&F values while cost of capital will be deflated using the Bank of England's (BOE) 2% target rate to calculate real values. This method is in-line with the W3 Interconnectors decision.

1. Introduction

This section gives an overview of Ofgem's response to the Financial Framework consultation for Window 1. It summarises stakeholder feedback and sets out Ofgem's final approach to various financial parameters under the cap and floor regime.

The decision we are making

1.1 We received 35 responses to the Consultation on Financial Framework for LDES Window 1 (referred to in this document as "the Consultation"). We have now decided on our final approach to the financial parameters within the C&F regime.

1.2 This decision document sets out the Consultation responses and Ofgem's final approach to the Financial Framework having considered the responses received.

1.3 Our remit comes from Government, following its 2024 LDES consultation, which tasked Ofgem with regulating and delivering the associated frameworks. The Clean Power 2030 and 2035 capacity needs highlight the urgency of policy development and Project delivery. Our decisions aim to enable timely progress, with eligible Projects selected and awarded C&F regimes in 2026, allowing assets to be online by 2030 and 2033 to benefit the GB energy system and consumers.

Ofgem's legislative framework and duties

1.4 The decisions in this document have been made to protect the interests of existing and future consumers, including their interests in the Secretary of State's compliance with the duties in sections 1 and 4(1)(b) of the Climate Change Act 2008 as well as their interests in the security of the supply of electricity to them. With the passage of the Energy Act 2023, Ofgem has a statutory net zero duty.

1.5 Where we have taken a decision to promoting competition we have considered to what extent consumer interests are protected and whether alternative approaches could better protect those interests.

1.6 We have had regard to the matters listed in s.3A(2), (3), (4) and 5 of EA89. In particular, the need to secure that all reasonable demands for electricity are met, the financeability of licence holders in respect of their licence obligations, and the need to contribute to the achievement of sustainable development.

1.7 We also now have a new growth duty to have regard to the promotion of sustainable economic growth through our regulatory activities. Our primary contribution to sustainable economic growth is through regulation that minimises energy costs, supports reliable and resilient energy supplies and keep energy markets functioning effectively. More detail on this duty is in our Multi-year Strategy.

1.8 We consider that the decisions in this document are best calculated to promote efficiency and economy on the part of licensees, and secure a diverse and viable long term energy supply.

1.9 The decisions herein reflect principles of transparency, accountability, proportionality, consistency, and targeting only cases in which action is needed.

Overview of this document and subsidiary documents

1.10 This document sets out our approach to calculating the administrative C&F rates of return, the process for Project-Financed applicants to access an Actual Cost of Debt (**ACOD**) floor, and how Projects requiring flexibility can bid using financial parameters. In this context, Project Finance refers to arrangements where third-party debt financing is raised specifically for the Project, typically using non-recourse debt, with lenders relying on the Project's cash flows for repayment.

1.11 The document also outlines the proposed cost and delivery incentives, along with end-of-regime arrangements for long-lived assets. The final CFFM and handbook, which will support consistent application of the framework and inform PAs, will be published following this decision.

1.12 Each section of this document begins with a summary of our Consultation position, followed by a summary of stakeholder responses. This is then followed by our final position, including the rationale for any changes made to our Consultation proposals in light of stakeholder feedback.

Response categories

1.13 All 35 responses to the Consultation were submitted via email to LDES@Ofgem.gov.uk. We heard from a wide range of stakeholders, including developers of LDES Projects, trade associations, investors, and others. We are grateful to everyone who shared their views, your input has helped shape the positions set out in this document.

1.14 To help with analysis, we grouped responses into the following categories:

a) Developers - companies involved in building or operating LDES Projects, including technologies such as Battery Energy Storage Systems (BESS), Compressed Air Energy Storage (CAES), Vanadium Flow Batteries, Hydrogen Batteries, and Pumped Storage Hydro (PSH).

b) Trade Associations and Representative Bodies – Organisations that represent the interests of the energy and storage sectors.

c) Other – Stakeholders not directly involved in developing or investing in Projects, such as advisory bodies and non-applicant contributors.

Confidentiality and publication

1.15 We identified 17 of the 35 responses as confidential, so we did not publish them. A further 9 did not respond to our confirmation of confidentiality and we are treating these as confidential. We published the remaining 9 responses, which were not marked as confidential. This approach promotes transparency while respecting the confidentiality requests of specific stakeholders.

Stakeholders' response

1.16 The following Trade Associations provided responses: British Hydropower Association, Electricity Storage Network, Energy UK, RenewableUK, Scottish Renewables. A summary of organisations that provided responses and the technology types are provided in the following tables:

Table 1: Stakeholder responses by technology type

Technology type	Stakeholder
BESS	Conrad Energy, EDF, EP UK Investments, Field, Frontier Power, Gresham House
PSH	Earba / Gilkes Storage, Foresight / Glenmuckloch, Glen Earrach Energy, Intelligent Land Investments Group, Quarry Battery Company, SSE Renewables
Other	Centrica, Cleanergi, Highview Power, Eku Energy, Equinor, Statera Energy, Statkraft, Voltwise
Not an Applicant	Bechtel, British Hydropower Association, CellCube Energy Storage, Electricity Storage Network, Energy UK, Form Energy, Haldane Energy, Hydrostor, Invinity Energy, Mutual Energy, RenewableUK, Scottish Renewables, Shell, Transmission Investment, Zenobe Energy

Table 2: Summary of stakeholder type:

Stakeholder type	Number of responses
Applicant	20
Non-applicant	10
Trade Association	5

Next steps

1.17 A set of documents has been published alongside this Decision, including the Eligibility Decision, PA Decision, Multi-Criteria Assessment (MCA) Framework, the National Energy System Operator (NESO)'s Cost Benefit Analysis (CBA) Methodology, Cost Assessment Guidance (CAG) and PA Data Submission Form (DSF). The final CFFM and handbook, will be published after this decision. Together, these publications move the LDES scheme into its next phase.

1.18 As set out in the LDES Window 1 MCA Framework and the Project Assessment Decision, Eligible Projects will have 8 weeks to complete and send their LDES Window 1 Project Assessment Forms and associated evidence to Ofgem. This eight-week period is referred as the Submission Period. The deadline for completing the Project Assessment Data Submission Form is 23:59 on 18 November 2025.

1.19 Ofgem will share relevant information from Projects with NESO and its advisors and will begin the PA after the Submission Period ends. The Initial Decision List, identifying projects proposed for C&F regime award, will be consulted on in Spring 2026. This will be based on the adjusted Economic Assessment ranking, Financial Assessment ratings, and Strategic Assessment. The Initial Decision List will highlight the Projects that perform best in the PA. We expect to make final C&F awards to Projects in Summer 2026.

1.20 Eligibility for the LDES C&F regime is based upon the evidence provided at the time of application. Whilst Ofgem may choose to revisit eligibility if there is a material change to the evidence upon which the original eligibility decision is based, we have elected not to revisit where the material change relates solely to revised connection dates or queue positions resulting from NESO's ongoing Connections Reform. It is our view that consumer interests are better served by allowing such Projects to proceed to the next C&F assessment stage.

1.21 However, we expect Projects to engage with NESO in order to clarify whether they remain deliverable in time on the basis of their expected connection date. If the expected connection date remains unclear at the point of our making awards, Ofgem may grant C&F regime subject to deliverability conditions where it is in consumer interests to do so.

Decision-making stages

Date	Stage description
19/06/2025	Consultation on LDES Financial Framework opened

17/07/2025	Consultation closed, deadline for responses
23/09/2025	Decision on LDES Financial Framework (this document) published with non-confidential Consultation responses
18/11/2025	Deadline for Projects to submit Project Assessment Data Submission Form, detailed Project costs, and all relevant data required for the Project Assessment stage including the CFFM.
Spring 2026	Initial Decision List (IDL) published & consultation launched
Summer 2026	Final Decision on C&F regime award (alongside Project Assessment Decision, and publication of Licence Conditions)

Related publications

Consultation on LDES Financial Framework (June 2025)

Consultation on LDES Project Assessment (May 2025)

Long Duration Electricity Storage application guidance (April 2025)

Long Duration Electricity Storage Technical Decision Document (March 2025)

Long Duration Electricity Storage Consultation: Government Response (October 2024)

Long Duration Electricity Storage Consultation (January 2024)

Decision on our proposed approach to interconnector project delivery delays as part of the timelines and incentives framework applied to the Third Window (November 2023)

Decision on Timelines and Incentives changes for the Third Cap and Floor Window for Interconnectors (November 2023)

General feedback

1.22 We believe that consultation is at the heart of good policy development. We are keen to receive your comments about this report. We'd also like to get your answers to these questions:

1. Do you have any comments about the overall quality of this document?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Are its conclusions balanced?
5. Did it make reasoned recommendations?
6. Any further comments

1.23 Please send any general feedback comments to stakeholders@ofgem.gov.uk.

2. Approach to C&F level setting for LDES

This section summarises the Consultation positions, stakeholder feedback and the decisions we have made on using competition to set C&F levels.

Questions

Q1. What are your views on our proposal to move beyond focusing solely on Project return rates at the C&F levels, towards a more flexible approach that allows Projects to tailor key parameters to the needs of their LDES Project archetype?

Q2. How well does the proposed competitive framework accommodate the differing risk profiles of various LDES technologies? Are there any technology-specific considerations that should be better reflected?

Q3. How can Ofgem best ensure comparability between bids given the bespoke nature of the proposed parameters? Are there specific normalisation techniques or benchmarks you would recommend?

Q4. What are your views on the proposed truth telling incentives? Do you think these will effectively discourage inflated or strategic bidding?

What we consulted on

2.1 In June, we consulted on whether competition should be used to set C&F levels for LDES Projects. We proposed that competition could offer flexibility, accommodate diverse technologies, and deliver better consumer value.

2.2 We set out a competitive model in which Projects would submit a bid package to be assessed composing of five key parameters:

a) Target rate of return (benchmarked at 4.47% Consumer Price Index with Housing costs (CPIH)-real for the floor and 7.31% for the cap),

b) Residual value (benchmark: zero),

c) Regime duration (minimum 20 years; benchmark: 25 years),

d) Interest During Construction (IDC) rate, and

e) Decommissioning cost (% of capex).

2.3 Projects could tailor bids to reflect technology-specific risks, with lower-than-benchmark bids accepted if in the consumer interest, and the administrative C&F levels to act as ceilings to protect consumers.

2.4 We consulted on a reward incentive to encourage honest bidding, namely an enhanced revenue sharing for the most competitive bids. We proposed that the top 25% of bids, based on the biggest percentage cut from the administrative C&F levels set by Ofgem, would receive an enhanced sharing rate on revenue above the cap. The proposed figure was 20%, a doubling of the 10% offered under the default regime. The competitiveness of bids will also be assessed as part of the Financial Assessment (FA) under the PA framework, where more competitive bids would score higher.

2.5 We also proposed using a fixed 2% inflation rate for indexation, and that tax would be treated using an upfront allowance based on the corporate tax rates in place at the time.

Stakeholder responses

2.6 Stakeholders provided mixed responses towards our approach to setting C&F levels for LDES. Responses broadly fell along technological lines with BESS and other battery classes in support of competition, while PSH and respondents representing multiple Projects being opposed. Most respondents agreed that the framework did not effectively accommodate the differing risk profiles of various LDES technologies. Our truth telling incentives saw overwhelming disagreement from most respondents citing that it could increase the prospect of strategic underbidding. Stakeholders remained unsure of how to best ensure comparability between bids, but there was broad consensus that technology specific benchmarking should be employed.

2.7 Stakeholders supported the principles of truth telling incentives but stated that the incentive for the 25% most competitive bids could provide harm instead of benefit, as this rewards Projects bidding the lowest C&F levels. Stakeholders highlighted risks of gaming, strategic underbidding, and undeliverable bids as Projects could race to the bottom to increase chances of selection at the expense of more robust Projects at a higher price.

2.8 Stakeholders raised concerns that the five parameters were too wide, and that accurate data could not be provided for all, especially before reaching Final Investment Decision (FID). Views on the individual parameters are as follows:

a) **Rate of return**: Multiple stakeholders raised concern around “winners curse” and potential technology bias. Some viewed competition as potentially distorting and, to address this, suggested raising the administrative ceiling.

b) **Residual value**: Strong opposition from a number of stakeholders, as they felt this would make long-lived assets unfinanceable.

c) **Regime duration**: Stakeholders generally supported the flexibility offered, but some suggested that this should be aligned to asset type and not a biddable parameter.

d) **Interest During Construction**: There was a lack of support for this being a competitive parameter, instead stakeholders would prefer the IDC to be an administrative assumption with some recommending technology-specific benchmarks.

e) **Decommissioning costs**: Stakeholders raised concerns that these costs are too uncertain to be a suitable parameter for competitive bidding.

2.9 Most stakeholders raised concerns about the proposed 2% fixed inflation rate, which aligns with the Bank of England's long-term target. They stated it could expose LDES C&F Projects to unmanageable inflation risk. Respondents also pointed out inconsistencies with other regimes in the energy sector, such as CfDs, and highlighted the potential for asymmetric risk. It was noted that the 2% target has not been consistently met over the past decade, meaning Projects would likely face financial uncertainty under this approach.

Our decision

2.10 Ofgem considers it in consumer interest to adopt a default administrative rate of return whilst still allowing for some flexibility in exceptional cases. In such cases, Projects may request a higher floor rate of return, supported by strong evidence. This flexibility helps ensure that high value Projects, as identified through our PA, can proceed where they might otherwise be undeliverable under a fixed approach.

2.11 Requests for a higher floor must include robust quantifiable evidence, such as, specifically and exclusively, an auditable financial model and qualitative risk analysis/business case, to show why the administrative floor is insufficient as a downside rate of return. Ofgem will assess these applications through a structured process, considering both the consumer impact of higher floor rates and Project competitiveness as part of the overall PA, alongside any other relevant factors.

Role of competition in setting C&F parameters

2.12 We still believe competition can deliver better outcomes for consumers by driving efficiency and value for money. In principle, a competitive process for setting C&F parameters could help identify efficient cost levels and reduce the chance of consumers paying at the floor. However, after reviewing stakeholder feedback and carrying out our own analysis, we have concluded that introducing a full competitive model for all five parameters in the first LDES C&F window would add significant complexity and risk. This could delay the delivery of infrastructure that the NESO says is needed by 2030 to support a reliable and affordable energy system. To avoid these risks, we will use an administrative approach for setting C&F rates of return in this first window.

2.13 That said, we still see value in introducing some competition where it adds the most benefit. Our approach focuses on simplifying the framework while keeping flexibility for Projects with different characteristics.

Rationale for simplification:

2.14 We have focused competition on two parameters for three main reasons: to keep the process clear, to allow flexibility for long-lived assets, and to maintain timely delivery.

2.15 Instead of requiring bids on all five parameters, Projects will now compete on two: regime duration and residual value. The default remains a 25-year regime with full capital recovery (i.e., zero residual value). This is designed to support the financeability of a wide range of LDES technologies, especially where long-term debt beyond 25 years is not available. This gives Projects a clear and stable baseline while ensuring most can secure finance.

2.16 Many LDES technologies are expected to operate well beyond 25 years. For these long-lived assets, we consider it is in consumers' interest to allow flexibility on regime duration and/or residual value, provided Projects can show that a longer regime and/or recognising residual value would deliver better value for money. This flexibility allows Projects to align bids with their asset characteristics, supporting efficient financing and reducing overall costs.

2.17 By focusing competition on regime duration and residual value, we aim to balance simplicity with flexibility. This approach encourages Projects to reveal efficient solutions for long-lived assets while keeping the process clear and proportionate. Recognising residual value can also lower the floor price, reducing the likelihood of consumer-funded payments. Overall, this targeted competition supports financeability, reduces delivery risk, and ensures timely delivery of infrastructure that supports a secure, low-cost energy system.

Default administrative regime

2.18 C&F levels are set using a 'building blocks' approach, as introduced in the Consultation. The cap sets the maximum revenue a Project can earn, while the floor sets the minimum, both subject to incentives and adjustments. Revenue refers to the amount a Project is allowed to earn to cover efficient investment, operating costs, and a fair return at the cap, or a downside return at the floor.

2.19 Whilst some elements like operating costs, decommissioning, and depreciation are common to both the cap and the floor, return and tax allowances differ. A key part of the calculation is the Project's RAV, which is Ofgem's way of measuring the efficient value of a Project's assets. RAV includes approved construction costs, maintenance costs, decommissioning costs and interest during construction (IDC), alongside assumptions on depreciation, return rates, and tax.

2.20 Every Project will receive the following administrative regime by default:

a) **Regime duration**. Projects will normally receive a 25-year regime. They may propose a shorter regime (minimum 20 years) if their Project life is shorter, or a longer regime if the asset is expected to last longer and to help lower the floor level. Any bid must be supported by suitable evidence as outlined in the Regime length flexibility and consumer safeguards sub-section below.

b) **Residual value**. Projects are expected to recover all capital investment over the regime, assuming zero residual value at the end. However, they may bid a non-zero residual value if their Project life exceeds the regime duration or to help lower the floor level, provided this does not negatively affect Project delivery.

c) **Target rates of return at the cap and the floor**. These rates of return are applied to the entirety of the Project's RAV. These will be set administratively by Ofgem, as detailed in Sections: 3 Designing the floor mechanism and, 4 Designing the cap mechanism.

d) **IDC rate**. The IDC rate is used to set allowances for interest incurred during construction. This will be set administratively by Ofgem, based on a benchmark rate that will vary depending on the length of the construction period. The indicative benchmark for 1-3 year tenors is 6.03% and for 5-7 years is 6.11%, further detail is provided in Section 5.

e) **Decommissioning costs**. Decommissioning costs will be set administratively by default. Projects are expected to provide a reasonable cost estimate for decommissioning activities and decommissioning fund management. Ofgem will assess cost estimates to ensure they are efficient, economic, and effective, and reflects the uncertainty around costs that may be incurred 20 to 25 years from now, or later for longer-lived assets. For such assets, Projects should explain the basis for their estimate, including how they have considered operations beyond the regime and what post-regime revenues may contribute to covering decommissioning costs. Ofgem recognises the challenges of long-term forecasting, and the regime allows for reopeners if future legal or regulatory changes significantly affect decommissioning requirements.

Regime duration flexibility and consumer safeguards

2.21 Through the pared-down competition process, Projects may request a regime longer or shorter than the default 25 years. To support this, developers must provide clear quantitative evidence that sets out:

a) Why the default regime duration, is not sufficient or not appropriate for technical characteristics of the assets; and

b) How the proposed change supports consumer interests, including demonstrating value for money and maintaining a level playing field with other Projects.

2.22 We recognise that longer regimes may help reduce floor levels, which could lower the chance of consumer-funded payments. However, extended inflation-linked floors can become more expensive over time (due to compounding effects), especially in later years. This raises concerns about inter-generational fairness.

2.23 The default 25-year regime offers a balanced approach, giving developers certainty whilst protecting consumer value for money. We note that quantitative evidence linking nominal asset life or depreciation may not be deemed sufficient when comparing to a compounding inflation-linked regime structure. As a result, the current default regime parameters should be assumed as the default framework.

2.24 Given these risks we consider that, depending on the regime duration bids by Projects, there may be a need to develop additional safeguards to protect consumers. We expect Projects to consider overall consumer value carefully when preparing submissions for PA.

2.25 We also recognise that a longer regime may improve a Project's score under the FA part of the MCA, particularly where it enables a lower floor bid. However, this can present a misleading picture if the long-term consumer cost risks are not fully considered. To address this, we will assess the full lifetime cost to consumers as part of the FA, including compounding sensitivities, ensuring that short-term benefits do not outweigh long-term affordability.

2.26 Finally, we note that this framework allows flexibility for regime durations shorter than 25 years. We expect Projects of all assets to consider carefully regime duration in preparing their submissions for PA. For the avoidance of doubt, we do not expect to allow regime durations in excess of 25 years for assets that would ordinarily have a shorter technical life, as we do not consider this would be in consumers interests.

Regime variations

2.27 We have set the administrative floor at a level we believe gives the right amount of downside protection for LDES Projects. We expect it to be sufficient in most cases and it remains the default approach, with Projects having the flexibility to bid on two parameters. Overall, we consider that the commercial and regulatory construct we have developed for LDES is one that ought to be investable to a wide range of Projects and technologies, taking into the overall allocation of risk and the levels we have decided to use for the C&F.

2.28 Noting however this wide range of potential Projects and technologies there may be exceptional circumstances where regime variations may be justified, where Projects are unable to secure delivery through the default regime or to propose viable changes to regime duration and residual value through the competitive process. The flexibility in requesting a regime variation is only included because of the wide range of technologies and financing models in this window. We expect such requests to be rare and will approve them only where strong evidence clearly shows that the default approach cannot enable delivery.

2.29 In such cases, the regime variation policy **will allow Projects to request a higher floor rate of return**. This reflects stakeholder feedback and our aim to keep the framework flexible and proportionate. Following the approach used in the interconnector C&F regime, Projects must explain why this additional change is essential to secure the financing needed to progress to operation.

2.30 Any proposal for regime variation must follow the criteria clearly set out in 2.21 a) and b), with the addition to a) of why the default approach, including flexibility on regime duration and residual value, and the Actual Cost of Debt (ACOD) Floor option are not sufficient.

2.31 Any request for a higher floor will be in well-evidenced, exceptional circumstances. It will be a technology-neutral assessment and evaluated against clear, objective criteria as outlined below, to ensure fairness and consistency.

2.32 Projects must provide robust quantitative evidence showing that the uplift is essential to meet lender requirements, rather than to improve equity returns or overall viability. Requests should demonstrate that Project costs and downside return rates justify a higher floor than Ofgem's administrative level, and that without this adjustment, the Project would not go ahead.

2.33 We will assess whether this evidence answers three questions:

a) Does it demonstrate conclusively that finance would not be forthcoming were the regime to provide the administrative floor rate of return?

b) Does it allow us to estimate precisely the minimum size of the required uplift to the floor rate of return? Bearing in mind that the floor rate of return applies to 100% of the RAV.

c) Does it show that a higher floor would benefit consumers, and that other options like the ACOD floor were considered but found unworkable?

2.34 We will require Projects seeking an uplift to submit an auditable financial model showing outcomes with and without the uplift, including sensitivities, to demonstrate why the Project is not bankable at the administrative floor and how the uplift addresses specific residual risks not otherwise mitigated in the regime design. The modelling must include analysis of the expected levered equity return at the floor and why that rate of return is appropriate as a downside scenario. It must also include analysis of the levered equity return at the cap, taking into account revenue sharing, and why the range of available returns is insufficient.

2.35 Projects must also provide a qualitative risk analysis explaining why the administrative floor is insufficient. This analysis must assess residual risk exposure relative to other C&F regimes (which have shown to be investable) and other Projects and technologies participating in the LDES C&F regime. This qualitative relative risk analysis alone will not be sufficient evidence.

2.36 We will assess requests through a structured process. This will begin with an eligibility and completeness check that the Project has submitted reasonable evidence. We will then re-run the FA using the Project's proposed floor rate to quantify the change in expected floor payments and risk transfer to consumers. Because a higher floor generally increases the likelihood of floor payments, the Project's FA score will reflect this effect. Consequently, a Project seeking an uplift would need to demonstrate significant strengths elsewhere in the economic or strategic assessments to remain competitive, where appropriate we may apply an approved uplift to the floor. Ofgem reserves the right to offer a floor level between the requested and the administrative rate.

2.37 To ensure fairness, we may decide to apply a similar principle to that used for the ACOD approach. Under ACOD, Projects must repay the difference between the

ACOD and the administrative floor as soon as revenues exceed the ACOD floor before any equity distribution is made. Likewise, Projects that choose not to use ACOD but instead request a higher floor rate of return through regime variation **may be required to repay any difference between the higher requested rate and the administrative rate before any equity distribution is made once revenues exceed the higher floor rate**. This approach will help maintain a level playing field across all Projects.

Technology-specific risk consideration

2.38 LDES Projects use a range of technologies, each with its own risks. Reducing the number of biddable parameters from five to two limits the flexibility originally proposed to reflect these technology-specific risks. However, the remaining parameters (regime duration and residual value) still provide important flexibility. They allow Projects to propose longer durations or recognise residual value, which may help reduce annual revenue requirements under the C&F regime.

2.39 We also considered whether other parameters should vary by technology. Some consultation responses suggested technology-specific rates of return at the cap and floor to reflect different risk profiles. After further review, we concluded there is limited basis for this without stronger evidence from Projects. While we recognise that risk exposure likely varies between technologies, the direction and scale of these differences are uncertain. More importantly, many risks are already mitigated through the C&F design, for example, the existence of the floor and the pass-through of efficient cost overruns. The latter is explained in the CAG published alongside this document.

Truth telling incentives and the risk of strategic bidding

2.40 We no longer see a need for a truth-telling incentive in the final framework. This is because competition on C&F rates of return has been removed, which was the main reason for such a mechanism. The simplified framework, which limits flexibility to regime duration and residual value, greatly reduces the scope for strategic behaviour. These parameters are less open to gaming than C&F rates of return and will be assessed through the FA, which focuses on expected floor payments and overall consumer value. Combined with robust PA and deliverability checks, this provides stronger and more transparent safeguards than a selective incentive mechanism.

2.41 Some stakeholders also questioned whether truth-telling incentives would have been effective and raised concerns about underbidding or unrealistic assumptions. By removing this mechanism and simplifying the competitive elements, we have addressed these concerns while maintaining strong incentives for efficient operation through a uniform increase in the revenue-sharing rate at the cap from 10% to 30%. We have provided a reasoning for this change in Section 4.

Inflation indexation

2.42 We have decided to adopt an outturn inflation indexation approach for Window 1 of the LDES C&F regime, using BOE's long-term inflation target to deflate. This aligns with the methodology applied in the interconnector regime. Under this approach:

a) Nominal cost of capital inputs will be deflated using the BOE's 2% target rate of inflation to derive real values for setting the C&F.

b) C&F levels will subsequently be indexed annually to outturn CPIH inflation.

2.43 In the Consultation, we proposed a fully fixed approach to inflation indexation, using a 2% long-term inflation assumption. We noted that indexation to outturn could lead to unfair outcomes for consumers, and a hybrid approach would be difficult to implement at this stage. Stakeholders raised concerns, and we agree, that using a fixed approach would expose Projects to significant inflation risk, particularly for long-lived assets, and could undermine investability. One respondent noted that inflation has often exceeded the BOE target, citing recent peaks of 11%, and stated that fixing assumptions for 25 years creates major basis risk.

2.44 Following the Consultation, we considered a range of inflation approaches including a fixed, outturn, and the semi-nominal approach being implemented in RIIO-3 with the goal to balance investability with consumer protection. While some of these approaches can in principle align debt and equity treatment more closely, delivering a workable semi-nominal approach for Window 1 would have been highly complex and introduced significant delivery risk. On balance, we have decided to adopt a real indexation approach using CPIH, consistent with the interconnector regime.

2.45 It is important to note that as inflation compounds over time this can introduce significant risk to future consumers, as explained in the Regime length flexibility and consumer safeguards section above. These impacts will be captured through the FA, where we model projected revenues and expected consumer payments, ensuring any potential exposure is transparently assessed.

2.46 We will keep the approach to inflation under review and consider any refinements, such as a semi-nominal approach or similar, for future windows.

Taxation

2.47 We have decided to maintain the approach to taxation as set out in the Consultation. The C&F regime will include an ex-ante tax allowance, consistent with interconnectors regime. For Window 1 Projects, the applicable tax allowance will be based on the UK corporate tax rate announced by the Treasury in the same calendar year that the C&F regime awards are made, together with technology-specific assumptions on capital allowance expensing rates. This includes rates announced for that year or for future years, provided the announcement occurs within the same calendar year as the award.

2.48 We consider this approach provides Projects with greater certainty over tax assumptions that will apply throughout the regime, compared to allowing actual tax paid to be treated as a pass-through cost, supporting effective financial planning and investment decisions. It also reduces administrative complexity by avoiding annual reconciliation of actual tax paid. While we acknowledge stakeholders concerns about potential changes in corporate tax rates over time, we believe the benefits of predictability and simplicity outweigh these risks.

3. Designing the floor mechanism

This section outlines our consultation position regarding the floor setting mechanism, summarises stakeholder feedback, and presents our final decision.

Questions

Q5. What are your views on our proposed approach to floor setting?

Q6. What are your views on our proposed performance-linked measures to access the floor and incentives below floor?

What we consulted on

3.1 The floor in the LDES C&F regime provides downside protection by ensuring a minimum level of revenue for Projects over the regime duration. This helps Projects manage the risk of low market returns that may not cover efficient costs and debt, reducing reliance on volatile prices.

3.2 We proposed three approaches to setting the floor:

a) **Administrative Floor**: Calculated based on standardised market benchmarks, such as iBoxx index for BBB-rated long-term bonds. The proposed rate was 4.47% CPIH-real, using market data from April 8, 2025.

b) **Actual Cost of Debt (ACOD) Floor**: Tailored for Project-Financed assets, this reflected competitively secured debt costs. It required oversight and a consumer protection backstop, either the administrative or bid-base floor, whichever was lower. Projects were required to repay any excess if the ACOD floor exceeds the benchmark.

c) **Competitive Bidding**: Projects could bid their own floor level across five parameters, provided it remained below the administrative benchmark. This allowed flexibility and risk alignment.

3.3 To access floor payments, Projects are required to meet a Minimum Availability Target (MAT), ensuring operational performance. If MAT is not met in a given year, clawback provisions apply to protect consumers.

Stakeholder responses

3.4 Stakeholders generally supported an administratively set floor using the iBoxx BBB-rated bond index. Many recommended adding a First-of-a-Kind (FOAK) premium, typically around 150 basis points, to reflect higher risks, especially for Pumped Storage Hydro and emerging technologies. There was concern that the proposed 4.47% CPIH-real rate is too low to attract investment, with calls for higher rates and more flexible inflation indexation to reduce basis risk.

3.5 The ACOD option was welcomed for Project-Financed models, but some noted its complexity and risk of strategic bidding. Respondents also called for clearer guidance, technology-specific adjustments, and greater transparency. Overall, stakeholders urged Ofgem to balance consumer protection with realistic financing needs to keep the regime investable across LDES technologies.

3.6 There was broad support for linking floor payments to a MAT to safeguard performance. Stakeholders agreed MAT should be Project-specific and exclude planned outages and force majeure events. However, many felt the current approach penalises underperformance without recognising overperformance. A symmetrical incentive structure was widely recommended to encourage high availability and align with other regulatory frameworks.

3.7 Stakeholders also stressed the need for clear MAT definitions, consistent treatment across different regimes, and appropriate protections for lenders. Aligning MAT requirements with Capacity Market obligations was seen as important to support bankability and avoid duplication.

Our decision

3.8 We will retain two floor-setting options: an administrative floor (default) based on a BBB-rated cost of debt benchmark, and an Actual Cost of Debt (ACOD) floor for Project-Financed assets. Projects can request a higher floor only in exceptional, well-evidenced cases through a Regime Variation, as outlined in Section 2.

3.9 The ACOD floor reflects actual financing terms but includes consumer protection measures and Ofgem oversight. Both approaches aim to balance bankability with consumer value, ensuring the floor acts as a safeguard against downside risk rather than a target or guaranteed return. Access to floor payments will depend on meeting a MAT, which ensures Projects receiving C&F support are available and delivering the benefits that justified the regime award.

Approach to setting floor

3.10 We have modified one of the two floor-setting approaches we are retaining under the regime in response to stakeholder feedback:

a) **Administrative floor**: This default approach applies to all Projects, providing a floor based on a notional cost of debt. It offers predictability and is well-suited to balance sheet–funded Projects, where financing is typically embedded within the sponsor’s wider corporate structure.

Since the cap and floor rates are each applied to the full RAV to determine the respective payment levels, gearing assumptions are less critical in this approach. This simplifies financial modelling and reduces sensitivity to individual capital structures.

In exceptional cases, Projects may request **a higher floor rate of return through a regime variation**, subject to the strict criteria noted in Section 2. Any approved increase may include clawback provisions if future revenues exceed the higher floor, and before any equity distributions are made.

b) **Actual cost of debt (ACOD) floor**: This option is **additional to the administrative floor** and available for Project Financed based Projects. It sets the floor based on the Project's actual, competitively secured cost of debt, covering only debt obligations. Similar to the interconnector ACOD model, it better reflects financing realities and supports tailored structures but requires extra oversight and safeguards to protect consumers.

Setting the administrative floor level

3.11 We have decided to retain our approach to calculating the administrative floor rate of return as per the Consultation, based on the iBoxx GBP Non-Financials 15+ BBB benchmark index, expressed in CPIH-real terms. To reduce financing risk and support timely delivery, we will set the floor return based on a Project's Final Investment Decision (FID) date, rather than at the eligibility window opening date of 8 April 2025. However, we will continue to use indicative figures based on 8 April 2025 for the PA.

3.12 The cost of debt benchmark will be calculated as the average yield over the 20 trading days preceding the FID. This rate will apply to the full RAV, consistent with established approach for electricity interconnectors. To express nominal index yields in real terms, we will use the BOE target rate of 2%.

3.13 **Rationale for retaining floor rate of return:** Our proposal to apply a BBB index cost of debt benchmark without any FOAK premium was based on our assessment of both the underlying risks and the de-risking measures included within the model. We did not receive convincing, quantitative evidence from Consultation respondents that this assessment was inaccurate. We have therefore decided to retain this proposed approach.

3.14 This is consistent with our experience from the interconnector C&F regime and our assessment of relative risk between interconnectors and LDES assets. Our decision reflects that, while LDES Projects face higher inherent revenue risk than point-to-point (P2P) interconnectors, the design of the LDES regime substantially mitigates these risks. Features such as a higher minimum level of revenue at the floor (BBB-rated compared to A/BBB for P2P Interconnectors), the option of an Actual Cost of Debt (ACOD) floor subject to Ofgem approval for Project-Financed assets, performance-linked access conditions, and cost treatment provisions. These features substantially reduce lender risk compared to a fully merchant model and reduce lender exposure to a level broadly comparable with other C&F regimes.

3.15 Our analysis, supported by CEPA, indicates that the differences in lender exposure between LDES and interconnector projects are not material once these protections are applied. Increasing floor rate without clear evidence of need could risk overcompensating Projects and increasing costs to consumers.

3.16 From an investor perspective, the floor is designed to provide a plausible downside case, not a target return. Its purpose is to support debt serviceability and bankability under adverse market conditions, while preserving strong incentives for Projects to operate actively in the market. We consider that for most Projects, a BBB benchmark achieves this balance. It offers a higher level of downside protection than the A/BBB blend used for interconnectors, recognising that LDES Projects face greater revenue uncertainty due to reliance on multiple revenue streams and potential cannibalisation.

3.17 **Rationale for higher floor rate of return through a regime variation:** While the default BBB-rated floor provides a consistent baseline for most Projects, some may face residual risks not fully mitigated by the regime. In such cases, the floor could become a binding constraint on viability rather than a safeguard. To avoid undermining delivery of strategically important Projects, we will allow requests for a higher floor rate as explained in Section 2. For this Projects must demonstrate through an auditable financial model, sensitivity analysis, and risk benchmarking, that the uplift is essential to ensure delivery and remains consistent with the regime’s principle of downside protection. This mechanism, available through a regime variation, ensures flexibility without compromising fairness, transparency, or consumer value.

Setting the Actual Cost of Debt (ACOD)

3.18 We will retain the ACOD floor variant as an option for Project-Financed LDES assets, enabling them to set their floor based on actual, competitively secured debt terms, covering debt obligations only. This approach improves bankability and expands the range of viable financing models.

3.19 We will apply a consumer protection backstop to the ACOD floor. Where the ACOD floor exceeds the administrative floor, the Project must repay the difference to consumers before making any equity distributions. This ensures fairness between balance sheet–funded and Project-Financed Projects.

3.20 We will oversee the debt funding process through a framework, based on the Debt Funding Competition (DFC) model used in the interconnectors (see Appendix 1 of the Long Duration Electricity Storage: Technical Decision). Each Project will lead its own DFC under Ofgem's oversight. Where the DFC outcome results in a lower floor than the administrative benchmark, our oversight will be minimal. We will fix the ACOD floor in real terms and index it to CPIH outturn inflation.

3.21 We will calculate the ACOD floor based on the financial terms secured at FID. Projects may fix eligible costs either at the time of regime award or in line with their debt-raising timeline. Final Project costs must remain within the range submitted during PA.

Performance linked floor access: Minimum Availability Target (MAT)

3.22 Stakeholder responses to the Consultation broadly supported the inclusion of a performance-linked mechanism to access floor payments. In light of this feedback, we are retaining our Consultation position to include a MAT as a condition for accessing the floor under the C&F regime.

3.23 The MAT links floor payments to actual operational performance, requiring Projects to maintain a reasonable level of availability and be ready to deliver energy when needed. Each Project will have a tailored threshold, excluding planned outages and force majeure events. This approach incentivises high readiness, especially during system stress, ensures floor payments go only to assets delivering value, and protects consumers from underperforming Projects.

3.24 We consider this approach proportionate and effective in aligning incentives with system needs while supporting Project financeability. To address the needs of Project-Financed LDES, we may allow temporary retention of floor payments below the MAT, subject to clawback, to improve lender confidence. A detailed approach to implementing the MAT will be developed as part of the licensing work, expected to start in Q3 2025.

4. Designing the cap mechanism

This section summarises our consultation on the cap-setting mechanism, stakeholder feedback, and our final decisions. We will retain the administrative cap using a notional cost of equity applied to the whole RAV.

Questions

Q7. Does the proposed cap design provide the right balance between incentivising efficient operation and sharing upside with consumer?

Q8. What are your views on the use of the CAPM and the proposed input assumptions (e.g. equity beta, RFR, TMR) for calculating the cost of equity for LDES? Are there refinements or alternatives you would recommend?

What we consulted on

4.1 The cap is the maximum revenue a Project can earn each year. Any extra revenue above this limit is partly returned to the consumer. This ensures fairness while keeping incentives for Projects to innovate and operate efficiently.

4.2 We proposed two approaches to cap setting:

a) The **administrative cap** is calculated using a notional cost of equity applied to the full RAV, based on the Capital Asset Pricing Model (CAPM). This includes an equity beta of 1.125, a risk-free rate of 2.26%, and a total market return of 6.75%, resulting in a cap rate of return of 7.31% in CPIH-real terms. This benchmark aligns with established regulatory practice.

b) Alternatively, Projects may propose a **competitive cap** level tailored to their specific risks and financing needs. These bids must remain below the administrative cap ceiling. This flexibility supports diverse technologies and business models, encouraging innovation and cost efficiency.

4.3 To further incentivise performance, we introduced a **soft cap mechanism**. Projects retained 10% of revenues earned above the cap, which maintained operational incentives while ensuring that most excess returns benefited consumers. This level was considered sufficient to encourage responsiveness without creating windfall gains.

Stakeholder responses

4.4 Respondents broadly supported the inclusion of a soft cap mechanism but overwhelmingly viewed the proposed 10% revenue sharing rate above the cap as insufficient to incentivise efficient operation or attract investment. Many stakeholders stated that the low sharing rate discouraged risk-taking, distorted dispatch incentives, and failed to reflect the commercial realities of LDES technologies. Many recommended increasing the sharing factor, citing Australia's 50% revenue share in the Long Term Energy Service Agreements (LTESA) scheme and the Dispatchable Power Agreement's 30% gainshare. Some called for technology-specific adjustments and more frequent reconciliations to reduce investor uncertainty. Overall, there was strong support for a more generous and flexible upside-sharing mechanism.

4.5 Respondents broadly supported the use of the CAPM to estimate the cost of equity but raised concerns about the input assumptions. The equity beta of 1.125 was viewed as too low and based on unsuitable comparators, particularly National Grid, which they viewed as unrepresentative of LDES risk profiles. Respondents recommended excluding regulated entities and instead using merchant-exposed firms to better reflect market and technology risks. Others suggested using different beta values for different technologies, especially for Stream 2 and TRL8 assets. Recommendations included aligning CAPM inputs with RIIO-3 decisions, updating the Total Market Return, and adjusting for inflation and tax changes. Feedback emphasised the need for a more tailored and transparent process.

Our decision

4.6 For Window 1, we will apply a single administrative approach to cap setting, using CAPM applied to 100% of the RAV. The cap rate of return will be set in CPIH-real terms, based on an indicative equity beta of 1.125 and an updated total market return of 6.9%, consistent with RIIO methodology and UKRN guidance. These parameters provide predictability, align with regulatory precedent, and protect consumers. In response to stakeholder feedback, the reference date for financial inputs will now align with FID. We have increased the soft cap sharing factor from 10% to 30% to strengthen operational incentives without raising the floor rate of return.

Approach to cap setting

4.7 Following consideration of stakeholder responses and further internal analysis, we have decided to apply a single approach to cap setting for Window 1 Projects. All Projects will be subject to an administrative cap level, calculated using benchmark return assumptions evaluated at a notional capital structure.

4.8 However, if a Project bids its preferred regime duration and/or a residual value greater than zero, its bid will be assessed accordingly. This creates the opportunity for a lower cap level and helps to deliver better outcomes for consumers.

4.9 Expected cap payments will not be an assessed metric under the FA, as any Project projected to receive cap payments already receives full marks in the FA. The administrative cap protects consumers by capping upside returns at a level deemed proportionate to the sector's risk profile.

Setting the administrative cap level

4.10 We will retain the administrative cap methodology as set out in the Consultation. **The administrative cap level under the LDES cap and floor regime is based on the same building blocks as the floor**. The main difference is the rate of return applied. For the cap, the return is calculated using the CAPM, while the floor return is set separately. The core methodology remains consistent, with the return assumption being the key variable.

4.11 Other parameters, such as the tax allowance, also differ to reflect the distinct revenue levels at the C&F. Despite these differences, the overall structure is aligned, supporting transparency and comparability across the regime.

4.12 The CAPM will be applied to 100% of the RAV using the following inputs:

a) Indicative equity beta of **1.125**, benchmarked to a set of listed comparators;

b) Risk-free rate based on the 20-trading day average yield on 20-year index-linked gilts, which implies an indicative rate of **2.26% CPIH-real** as of 8 April 2025, and as adjusted by a 26 basis point RPI–CPIH wedge;

c) A total market return of **6.9% CPIH-real**, updated to align with Ofgem's latest RIIO-3 Draft Determination for onshore network companies.

4.13 These inputs result in an indicative cap rate of return of **7.48% CPIH-real**. We consider this approach proportionate and consistent with regulatory precedent, including the interconnector regime.

Rationale for financial parameters

4.14 **Equity beta**: the beta was derived from a five-year average of asset betas for six listed comparators (Drax, SSE, Iberdrola, Ørsted, RWE, and National Grid) using equal weighting and a notional gearing of 50%. While some stakeholders questioned the inclusion of National Grid due to its lower merchant risk, we have retained it for three reasons:

a) It ensures consistency with the methodology applied in previous C&F regimes, supporting regulatory stability and predictability.

b) National Grid, despite its regulated core business, is a major UK-listed energy infrastructure company with exposure to electricity markets and policy risk. Including it, helps maintain a diversified comparator set alongside companies with higher merchant exposure.

c) Beta estimation is inherently uncertain and sensitive to the choice of comparators. A balanced set of energy companies, including National Grid, provides a more stable and representative estimate for setting the cap rate of return. Excluding lower-risk comparators could overstate systematic risk and lead to unnecessarily high returns at consumer expense.

4.15 We understand the concerns raised about using a single equity beta, including suggestions for technology-specific or range-based values. While risks do vary across LDES technologies, we have chosen to apply a single beta for Window 1 to maintain consistency and predictability. The beta reflects a sector-wide view of risk, based on a balanced set of listed energy companies. Broader risk considerations are addressed through the overall C&F regime design, including the floor methodology and the flexibility around regime duration.

4.16 **Risk-free rate (RFR)**: The RFR is benchmarked to long-dated UK Government gilts, consistent with established regulatory practice and UKRN guidance. This provides a transparent and objective measure of the time value of money and systemic risk-free return, which should not be used to reflect project-specific risk. Project-specific risks are addressed through other parameters such as beta and through the C&F regime design. Maintaining a stable and well-understood RFR methodology supports investor confidence, while ensuring consistency with the approach applied in the interconnector regime.

4.17 **Total market return (TMR):** We have updated the TMR to align with Ofgem's latest Draft Determinations for RIIO price controls. TMR is a market-wide parameter that reflects the long-run expected return on equity across the economy and is not intended to capture sector-specific or project-specific risk. This update ensures consistency with UKRN guidance and regulatory practice.

4.18 We initially selected 8 April 2025 as the reference date for collecting financial data to provide early clarity and support timely delivery against the Clean Power 2030 target. Following stakeholder feedback, we will now align the reference date with FID. In this decision document we continue to use indicative figures.

Sharing the upside: soft cap design

4.19 We have decided to increase the revenue sharing rate above the cap from 10% (as consulted on) to 30% for all successful Projects under Window 1 of the LDES

C&F regime. This responds to stakeholder feedback that the sharing factor is a key element of the overall risk–reward balance. The change improves investability without raising the floor, maintaining consistency with the interconnector regime. A 30% rate strengthens incentives for performance beyond the cap while ensuring most excess revenues continue to benefit consumers.

4.20 In considering the revenue sharing rate, we reviewed sharing factors from other LDES regimes and how these contributed towards the overall risk-reward balance. This included reviewing Australia's LTESA scheme, as it was mentioned in numerous Consultation responses, which is a Contract for Difference (CfD) scheme and has a 50% sharing factor. However, we did not deem this level to be appropriate for our C&F scheme as in LTESA, the higher sharing cost exists to compensate projects for their greater risk exposure – for example, projects in LTESA carry 100% of construction risks, while in our C&F scheme, 100% of economic and efficient costs can be added to the RAV as explained in Section 6.

4.21 We consider the revised sharing level proportionate and consistent with the regime's objectives: improving the risk–reward balance, maintaining strong operational incentives, and delivering consumer value.

5. Capital and operational costs

This section outlines what we consulted on for capital and operational costs under the LDES C&F regime, summarises stakeholder feedback, and sets out our decisions on decommissioning costs and IDC rates as well as marginal cycling costs.

Questions

Q9. What are your views on the proposed capital cost components for determining the RAV and C&F levels, including the equity and debt transaction cost allowances?

Q10. Do you agree with limiting reopeners during the operational phase to opex (after 10 years) and decommissioning (if there's a legal change)?

Q11. What are your views on the treatment of decommissioning costs and IDC particularly around timing of recovery, Project delays, and legislative changes?

Q12. What are your views on the proposed IDC rate approach and the option for Projects to bid their own rate? Should riskier technologies receive a different rate?

What we consulted on

5.1 We proposed to capitalise a broad set of costs into the RAV, which then provides the basis for depreciation and returns. These components include development expenditure (devex), construction capital expenditure (capex), strategic spares, replacement expenditure (repex), decommissioning costs, interest during construction (IDC), and transaction costs associated with raising debt and equity. All items would be assessed for efficiency and economic delivery and reflected in the CFFM.

5.2 We proposed that Projects estimate decommissioning costs as a percentage of capex and bid the share to be recovered. IDC was presented as a potential bid parameter, subject to benchmarking and regulatory oversight. We indicated allowances for transaction costs on equity and debt against the opening RAV.

5.3 Separately, we treated operating expenditure (opex) outside the capital cost base. Opex was added to the depreciated RAV and included controllable costs, pass-through items, and corporation tax. Marginal cycling costs were also considered, these refer to the additional expenses incurred each time the storage system is charged and discharged.

5.4 To manage uncertainty across long asset life, we proposed limiting cost reopeners to opex (after 10 years) and decommissioning (if triggered by legislative change).

Stakeholder responses

5.5 Most stakeholders supported the list of capital cost components and the principle of including transaction costs (5% equity and 2.5% debt transaction cost) with some asking for flexibility to reflect evidenced actuals. Many called for strong transparency and independent validation to exclude ineligible or inflated costs. Several requested clearer definitions and evidence requirements for marginal cycling costs and asked whether Project-specific items such as grid studies or community measures would be included. There was broad support for assessing technology-specific needs while keeping consumer protection paramount.

5.6 Views on reopeners were mixed. Some supported an opex reopener at year 10, others stated that LDES risk profiles justify more frequent or more targeted reopeners (typically every five years), citing inflation exposure, evolving operating costs and regulatory change. Many suggested pass-through treatment for clearly uncontrollable costs. There was strong support for a decommissioning reopener in the event of legislative change and to recognise planning authority requirements and other material changes alongside changes in law.

5.7 Stakeholders generally supported expressing decommissioning costs as a percentage of capex with recovery spread over time. Many did not support competitive bidding for decommissioning recovery and warned this could introduce risk and reduce comparability. On IDC, some favoured benchmarking while others preferred Project-specific rates based on lender evidence. There were strong views on distinguishing developer-caused delays from external factors so that IDC treatment remains fair and bankable.

5.8 Many supported using a Weighted Average Cost of Capital (WACC)-based benchmark to calculate IDC rates and adjusting for construction risk and duration. Several cautioned that making IDC a competitive bid parameter could encourage strategic underbidding and weaken bankability. Views were split on differentiated IDC for riskier technologies: some supported it to reflect risk, while others suggested a preference for consistency to avoid unnecessary consumer cost. Some respondents stated a case for uplifts or premiums for technologies like PSH to reflect development and delivery risk. Across responses there was emphasis that IDC must reflect real financing costs and should not become a barrier to investment.

Our decision

5.9 We will retain the overall approach to capital cost treatment set out in the Consultation, with one change. IDC will not be a bid parameter. Instead, Ofgem will set IDC administratively using a WACC-based approach. Projects may still submit their own decommissioning estimates. However, decommissioning will no longer be a bid parameter that influence scoring in the FA. Ofgem will assess submitted estimates to ensure they are economic, efficient, and proportionate, recognising the long-term uncertainty involved.

5.10 All other aspects remain as consulted. These include the components that form the RAV, the treatment of decommissioning, the treatment of financial transaction costs and the use of reopeners during operations.

Capital costs

5.11 Projects must submit capital cost data using the DSF. This should follow any guidance in the DSF, the CAG and the MCA Framework, published alongside this decision. We will carry out a detailed cost assessment of all submitted capital costs in line with the CAG and with the overarching objective of protecting consumers and ensuring fairness for Projects. Where necessary to achieve these objectives, we may also take into account other relevant factors not explicitly covered in the Guidance. As part of this review, we may adjust the submitted figures if we find costs that are inefficient, uneconomic, unjustified, or include errors, before adding them to the C&F RAV for selected Projects.

5.12 As set out in the CAG, Projects will be required to submit a low (P10) and high (P90) estimate of their capital costs alongside the central (P50) estimate. While the initial C&F levels will be calculated based on the central estimate, we would generally not expect cost overruns at the Post-Construction Review (PCR) stage to exceed the difference between the central and high estimate (see Section 6 for a more detailed discussion of this). Ofgem will assess these estimates to inform both the PA and the C&F levels.

Treatment of decommissioning costs

5.13 Projects must provide a clear overview of their decommissioning strategy and associated cost estimates. These will be assessed by Ofgem to ensure they are efficient, economic, and proportionate, and benchmarked against other submissions to support value for money. Projects will no longer be able to bid their own decommissioning assumptions, and decommissioning will no longer influence scoring in the FA.

5.14 Given the long-term nature of these costs, often 20 to 25 years away or more for longer-lived assets, Projects should explain the basis for their estimates. This should include how post-regime revenues may be used to cover a proportionate share of decommissioning costs, reflecting the asset’s life beyond the regime.

Ofgem recognises the challenges of long-term forecasting, and reopeners will remain available where there is a material change in law or regulation affecting decommissioning requirements.

5.15 This approach ensures consistency and fairness across Projects while maintaining a focus on value for money. Removing decommissioning as a biddable parameter simplifies the FA and reflects the uncertainty of forecasting distant costs. Requiring a clear strategy and cost estimate, alongside reopeners for material legal changes, balances accountability with flexibility. Considering post-regime revenues supports balanced cost recovery aligned with asset life.

Interest during construction (IDC)

5.16 IDC will be determined administratively using a WACC-based approach, consistent with the methodology we consulted on and currently apply to interconnectors and offshore transmission operators (OFTOs). The IDC allowance aims to reflect the cost of debt and equity during construction, adjusted for LDES-specific construction durations, and will be calculated at FID. Our overall approach to IDC remains aligned with interconnectors and will be calculated using the following methodology:

a) **Debt component**: Current figures are based on BBB-rated GBP corporate bond yields of a tenor aligned with expected construction duration of each type of LDES Project. We will review BBB against A/BBB to align with IDC rates across Ofgem. These nominal yields will be converted to real terms using the same approach as for the administrative floor rate of return. We do not, however, propose to update this comparison by, for example, carrying out further analysis to interpolate or extrapolate yields at different tenors. This is because we consider the proposed approach to provide a reasonable and proportionate estimate without introducing unnecessary complexity or uncertainty. We will set the rate based on a weighted average, with two-thirds weighting on the spot yield and one-third weighting on the one calendar year average yield.

b) **Equity component**: Calculated using the Capital Asset Pricing Model (CAPM), consistent with the administrative cap methodology but adjusted for construction-phase risk. The **Risk-Free Rate** will be based on the 20-trading day average yield of long-dated UK index-linked gilts of a tenor comparable to the construction duration, converted to CPIH-real terms. The **Total Market Return** will align with Ofgem's latest RIIO and interconnector benchmarks, currently estimated at 6.9%. We will apply an **Equity Beta** of 1.125, consistent with the Window 3 interconnector benchmark, reflecting the risk profile of LDES during construction.

c) **Gearing assumption**: Aligned with interconnectors, the IDC gearing assumptions will be 37.5% which will be applied to each year's expenditure.

5.17 We have set IDC rates using the approach outlined above and decided to use two broad tenor groups, as we consider this proportionate and avoids unnecessary complexity. The indicative rates are:

a) For 1-3 year tenor an IDC rate of **6.03%**

b) For 5-7 year tenor an IDC rate of **6.11%**

5.18 If Project submissions indicate materially different construction durations with robust evidence, we may revisit tenors and adjust IDC rates after assessment but will ensure consistency across Projects within each technology group.

5.19 Table 3: Indicative value input parameters of IDC for LDES with varied tenor lengths (BBB)

	1-3 Year Tenor	**1-3 Year Tenor**	**5-7 Year Tenor**	**5-7 Year Tenor**
Parameter	**Low**	**High**	**Low**	**High**
Debt yield	5.34%	5.34%	5.58%	5.58%
Transaction costs	0.00%	0.00%	0.00%	0.00%
Cost of debt	5.34%	5.34%	5.58%	5.58%
Risk-free rate	2.05%	2.05%	2.17%	2.17%
Total Market Return	8.94%	9.04%	8.94%	9.04%
Asset beta	0.50	0.90	0.50	0.90
Gearing	37.50%	37.50%	37.50%	37.50%
Equity beta	0.80	1.44	0.80	1.44
Cost of equity	7.56%	12.11%	7.58%	12.06%
Vanilla WACC	6.73%	9.57%	6.83%	9.63%
CPI	2.00%	2.00%	2.00%	2.00%
CPI-real WACC vanilla	4.64%	7.42%	4.74%	7.48%

5.20 Table 4: Indicative IDC rate

	1-3 Year Tenor	**5-7 Year Tenor**
Indicative IDC rate	**6.03%**	**6.11%**

Financial Transaction cost

5.21 We have decided to maintain allowances for financial transaction costs associated with raising both equity and debt, consistent with our Consultation position:

a) For equity, the allowance is **5% of opening RAV** at the start of the operational period to reflect the economic and efficient costs incurred in raising equity finance, such as legal and advisory fees.

b) For debt, the allowance is **2.5% of opening RAV** at the start of the operational period to reflect similar efficient and economic costs.

Treatment of opex

5.22 Operational expenditure (opex) will be split into two categories: **controllable opex and uncontrollable (Non-Controllable) opex,** consistent with the approach set out in our Consultation. Controllable opex refers to costs that Projects can reasonably influence, such as routine maintenance and staffing. These costs will be subject to a detailed cost assessment and will form part of a fixed annual allowance, which will act as one of the building blocks in setting the C&F levels for each Project.

5.23 Non-controllable opex refers to costs outside the Project’s reasonable control (for example, certain GB licence fees or property rates, where applicable). These will be treated as pass-through items, subject to evidence and verification, and added back in full. This ensures that Projects are not penalised for costs they cannot reasonably control, while still requiring evidence that these costs were managed responsibly. This approach mirrors the treatment of non-controllable costs in the interconnector C&F regime and reflects our Consultation position.

5.24 As with capex, controllable opex estimates will be based on Project submissions in the DSF. We will carry out a detailed cost assessment of submitted controllable opex estimates in line with the CAG and may adjust them if evidence is insufficient or if costs are considered uneconomic or inefficient before they are used as a C&F building block.

Marginal cycling costs

5.25 Some costs faced by LDES Projects will vary with the amount of energy cycled (i.e. charged and discharged) by the asset. These costs may also change over time and will therefore be treated separately from the fixed opex allowance. On a regular basis, we expect Projects to submit marginal cycling costs for their asset in £/MWh cycled across different charge and discharge rates, these will be benchmarked against Projects of a similar technology type.

5.26 Ofgem considers it reasonable to treat marginal cycling costs as a type of Market-Related Cost (MRC within the LDES C&F regime for Window 1). In the interconnector regime, MRC is calculated as the total of three elements: Error Accounting Costs (settling energy imbalances under the GB Balancing and Settlement Code), Firmness Costs (payments to users under firmness arrangements), and Trip Contract Costs (costs under trip contract agreements). These costs differ from controllable or non-controllable operating costs because they are driven by market conditions and commercial choices rather than fixed obligations.

5.27 Whilst we expect marginal cycling cost for LDES to reflect the actual amount of energy cycled by the Project in each period, allowing full pass-through could weaken incentives to minimise costs and could lead to inefficient behaviour. Even when system value is low, a Project might still cycle because its costs could be reimbursed under the C&F regime, regardless of whether the action delivers system benefit or profit. Instead, our approach to marginal cycling costs may follow a similar approach to MRC under the interconnector regime: these costs could be deducted from gross revenues when calculating Assessed Revenue and be subject to Ofgem review and approval to ensure they are economic and efficient. This approach will be considered in detail as part of the licence conditions and confirmed through the licence consultation process.

Cost assessment reopeners during operational phase

5.28 We will retain a limited and targeted approach to reopeners to maintain regime stability while allowing for adjustments where necessary. Reopeners will apply only in the following circumstances:

a) **Opex**: A review (or "reopener") can only happen after the regime has been running for at least 10 years, and then only once every 10 years after that. Either Ofgem or the Project can request this review.

b) **Decommissioning**: A review (or "reopener") can only happen if there is a legislative change that materially affects decommissioning costs used to set the C&F levels.

5.29 Further details on our approach to costs treatment will be set out in the LDES Special Licence Conditions. Where details are currently missing in our decision documents for LDES Window 1, Projects should familiarise themselves with the approach taken in the interconnector regime, as set out in the Special Licence Conditions for C&F projects. The details for LDES will be developed as part of the licence development workstreams, which we expect to start in Q3 2025.

6. Cost and delivery incentives

We have moved away from our consulted position as stakeholders were opposed to both options. Our cost incentive approach will be to add all economic and efficient cost overruns to the RAV as per the interconnector model. For delivery incentives, IDC adjustments, or graduated levers will not be used. Force Majeure provisions will remain mirrored to the interconnector regime, with a 2-year backstop date available for accepted requests.

Questions

Q13. What are your views on the types of cost efficiency and delivery performance incentives included in the regime?

Q14. What is your preferred approach to cost incentives (e.g. cost sharing vs. outturn comparison), and how should these be appropriately calibrated?

What we consulted on

6.1 We proposed measures to encourage timely and cost-efficient delivery. These included:

a) Cost incentives:

(1) RAV adjustment: Upward or downward changes to the Regulatory Asset Value based on outturn costs, with a 50:50 sharing of efficient overruns.

(2) Outturn comparison: Allowing efficient cost increases into RAV, with clawback if floor payments were triggered.

b) Delivery incentives: Adjusting the IDC rate for early or late completion and considering clawbacks linked to delays. We committed to force majeure provisions for uncontrollable events.

Stakeholder responses

6.2 Most stakeholders opposed the introduction of specific cost and delivery incentives, stating that existing mechanisms such as the Post Construction Review and natural commercial pressures already provided sufficient discipline.

6.3 Many stakeholders, especially those representing capital-intensive technologies like Pumped Storage Hydro, warned that the proposed 50:50 cost-sharing and clawback mechanisms would increase financing risk, reduce investor confidence, and add unnecessary complexity. Several respondents stressed the need for clearer definitions of "efficient" costs and broader force majeure provisions to protect against uncontrollable delays. A minority supported delivery incentives like IDC rate adjustments, but most questioned their effectiveness or preferred simpler, ex-post cost reviews.

6.4 Stakeholder views were divided between the RAV adjustment and outturn cost comparison approaches, but neither received broad support. Many respondents preferred the outturn comparison model, citing its alignment with the interconnector regime and its flexibility to accommodate unforeseen costs. However, several stakeholders opposed clawbacks of floor payments, stating that they added retrospective risk and undermined the value of the floor.

6.5 Supporters of the RAV adjustment model valued its upfront clarity but warned that benchmarks must be realistic and efficiency tests transparent. A number of stakeholders rejected both models entirely, recommending reliance on robust cost assessment and ex-post reviews.

6.6 Overall, support for new incentives was limited, with widespread concern that they could undermine investability and increase the cost of capital. Respondents consistently highlighted the risk and complexity introduced by both proposals, emphasising the need for simpler, more predictable mechanisms that can effectively support investment across a diverse range of LDES technologies.

Our decision

6.7 **Cost incentives:** After considering stakeholder responses, we have simplified our approach to cost and delivery incentives. We will not proceed with 50:50 cost sharing. Instead, our decision is that all economically and efficiently incurred cost overruns can be added to the RAV without clawback post regime, as per the interconnector model. Well-evidenced cost overruns up to the high (P90) capex estimate initially provided by each Project will be included in the RAV unless they are found to constitute Demonstrably Inefficient or Wasteful Expenditure (DIWE).

6.8 Any cost overruns which result in overall capex for each Project exceeding the high (P90) estimates will only be considered if the Project provides strong evidence. Projects must:

a) Explain the reason for the overrun, whether due to a specific circumstance or force majeure (FM), and

b) Set out the costs linked to the overrun.

6.9 For (a), Projects must show that the overrun could not have been avoided or reduced. For (b), they must show that the costs were economic and efficient. By default, any overruns above the P90 level will be treated as inefficient. They will only be accepted if the Project can demonstrate that the overruns could not have been predicted, reduced, or avoided by alternative action.

6.10 **Delivery incentives**: We will not apply IDC adjustments or clawbacks as initially proposed in the Consultation. We will also not introduce graduated levers as a delivery incentive.

6.11 We will align our delivery incentives more closely with those used in the interconnector regime. If a Project fails to deliver by 2030 or 2033 without a recognised delay event or FM, or by 2032 or 2035 with an approved extension, they will need to repay part of any future floor payments they receive. Similar to the interconnector Payback Mechanism for Delays, the amount repaid will be proportionate to the delay. This approach keeps the default 25-year regime length or the approved regime duration for a Project. It encourages timely delivery and provides clarity for investors while protecting consumers.

Rationale for our decision

6.12 The Consultation options had limited support, so we are introducing a simpler model that reduces any potential risk and complexity. This will improve outcomes for consumers by increasing the likelihood of securing the investment needed for a reliable and diverse long-term energy supply. Cost efficiency will continue to be managed through our wider regulatory processes, including scrutiny of capital and operational costs within the regime.

6.13 We are confident in this approach as we apply strong upfront scrutiny of Project submissions. Projects must provide robust and well-evidenced cost information. We will make adjustments where needed and reject Projects if submissions are not credible. Our assessment will model costs up to the P90 level to test overall value.

6.14 We also expect Projects to manage costs actively. This includes using contracting strategies to lock in prices where it is economic and efficient, and applying other cost control measures. These steps, combined with our oversight, mean we can allow some flexibility on outturn costs without adding extra incentives.

6.15 Regarding delivery incentives, we agree with stakeholders that directly adjusting the IDC rate would not provide a strong incentive for early delivery or a meaningful penalty for delays. Instead, we are aligning with the interconnector delivery incentive framework. This approach keeps the same risk–reward balance across regimes and gives Projects a clearer and more predictable structure. We consider the overall incentives framework strong enough to ensure efficiency and timely delivery without adding further incentives.

Force majeure

6.16 We will maintain the approach set out in the Consultation regarding the treatment of delays and FM under the LDES C&F regime. Our policy objective remains to ensure fair risk allocation between Projects and consumers by distinguishing between delays within a Project's control and those caused by FM events.

6.17 For the pre-operational period, we will follow the approach in the Technical Decision Document (TDD). Track 1 and 2 Projects will be able to request a deadline extension to 2032 and 2035, respectively, if delays are caused by FM events, and supported by clear evidence through a request for extension. Approved requests will not incur penalties. If a request is rejected, or delivery occurs after these dates, Projects will be subject to a payback mechanism for delays through recovery of floor payments proportionate to the delay. This is broadly consistent with our approach to Window 3 of the interconnectors. The backstop dates for LDES Window 1 Projects are:

a) Track 1: 31 December 2032

b) Track 2: 31 December 2035

6.18 For the operational period, FM provisions will mirror those in the interconnector C&F regime, covering events beyond the reasonable control of LDES operators.

6.19 The detailed policy and related licence provisions will be developed as part of Ofgem's work on the wider licencing framework and specific licence conditions for LDES Window 1 Projects. Ofgem will publicly consult on FM related licence provisions (both for pre-operational and operation periods) and stakeholders will be able to provide their feedback on these proposals.

7. Financial resilience

This section outlines our proposals on financial resilience measures, a summary of response by stakeholders and our final decisions.

Questions

Q15. Does our proposed mix of gearing caps, ringfencing, and financial reporting strike the right balance between financial resilience and flexibility for LDES Projects? If not, what would you change?

What we consulted on

7.1 In the Consultation we proposed measures to ensure financial resilience in LDES Projects under the C&F regime. Our aim was to protect consumers and maintain system integrity by introducing proportionate controls, including a gearing cap, asset ringfencing, and regular financial reporting.

7.2 We recognised that LDES Projects may have distinct risk profiles, with limited follow-on finance, minimal contagion risk, and no direct consumer fund exposure. However, the regime's structure creates circularity risks because the link between debt costs and the floor means that excessive debt could raise both borrowing costs and the floor level, undermining the regime. The proposed gearing cap aligns with precedents in other regulated sectors.

7.3 We also proposed ringfencing provisions to prevent equity holders from extracting hidden value and to safeguard regulated assets. These included restrictions on asset disposal, security arrangements, and cross-default clauses. In addition, we proposed annual financial reporting requirements covering key metrics, gearing forecasts, financing arrangements, and risk management narratives. These disclosures were intended to support early intervention and consistent oversight.

Stakeholder responses

7.4 Stakeholders broadly supported ringfencing and regular reporting as reasonable safeguards. Views on the 80% gearing cap were mixed. Some supported it as a prudent limit aligned with infrastructure norms, while others considered it unnecessary or too restrictive. Several stakeholders suggested alternatives such as Debt Service Coverage Ratio (DSCR) metrics or higher gearing thresholds. Others warned that the proposals resembled those for monopoly networks and could impose disproportionate burdens on LDES Projects. Many called for clearer implementation guidance, particularly around asset disposals, refinancing disclosures, and regulatory intervention triggers. Overall, stakeholders supported resilience measures but urged Ofgem to tailor them to the diverse financing structures and commercial realities of LDES technologies.

Our decision

7.5 We will continue with the measures consulted on to maintain the integrity and credibility of the regime. These measures are necessary to manage the interaction between corporate structure, capital structure and floor calibration, and to minimise contagion risks that could undermine long-term investment in regulated energy assets. The measures are:

a) An 80% gearing cap

b) Asset ringfencing provisions, and

c) Annual financial reporting requirements.

Rationale for our decision

7.6 We still believe an 80% gearing cap is appropriate for LDES C&F Window 1. Removing the cap could weaken financial resilience, while raising it further may make debt providers less willing to invest because equity would be reduced. This would not be in consumers' interests if it reduces investment appetite and potentially delays the development of Projects needed to cut system costs.

7.7 Our asset ringfencing provision remains as consulted on:

a) A restriction on asset disposal without written approval from Ofgem

b) A restriction on granting charges, liens, or other forms of security over regulated assets unless approved by Ofgem

c) A prohibition on including cross-default clauses in financing arrangements, or taking on commitments that include such obligations, where a default by an affiliate or other relevant party could trigger a default by the LDES operator, unless Ofgem has given written consent.

7.8 Our annual reporting requirements include:

a) Key financial metrics such as cash flow, profitability, liquidity and gearing;

b) Details of financing arrangements and anticipated refinancing events;

c) Dividend payments and equity movements, with justifications;

d) A narrative explanation of financial risks and how they are being managed.

7.9 The detailed financial resilience measures will be developed as part of the C&F licence provisions for Window 1 Projects, which are expected to start in Q3 2025.

8. C&F payments and charging mechanism

This section outlines our proposals on C&F payments and charging mechanisms, a summary of response by stakeholders and our final decisions to implement a BSUoS charging system.

Questions

Q16. Which charges - TNUoS or BSUoS - do you consider more appropriate for funding cap and floor payments and receipts, and why?

What we consulted on

8.1 In the Consultation, we outlined our proposed approach for managing payments under the LDES C&F regime. We confirmed that network charges would be used to fund payments when Project revenues fall below the floor or exceed the cap. Our preferred mechanism was the Balancing Services Use of System (**BSUoS)** charge, which we considered more suitable than the Transmission Network Use of System (**TNUoS**) charge.

8.2 BSUoS charges aligned better with the balancing and flexibility role of LDES technologies, which are not transmission assets. Unlike TNUoS, BSUoS charges are recovered through volumetric electricity usage, making them more equitable and easier to implement. We noted that TNUoS would require complex code modifications and could result in less fair cost distribution across consumers.

8.3 Ofgem proposed that NESO act as the central intermediary for managing payment flows. NESO would collect BSUoS charges from Suppliers and distribute floor payments to Projects when needed. Conversely, when Projects earned above the cap, NESO would reclaim surplus revenues and return them to consumers. The amounts due will be based on outcomes from the regime's assessment periods, while the actual payment flows will follow the annual BSUoS charging periods to support predictability. All transactions will be governed by licence conditions and reflected in BSUoS tariffs to ensure accountability and traceability.

8.4 BSUoS charges are recovered from electricity Suppliers who may pass these costs onto consumers. To maintain financial stability, NESO may adjust BSUoS tariffs mid-year if actual cap or floor payments diverge from forecasts. Any under or over-recovery is reconciled in future charging periods, ensuring that the scheme remains cost-neutral over time and supports predictable supplier billing.

Stakeholder responses

8.5 Most respondents supported using BSUoS charges to fund C&F payments, stating that BSUoS better reflected the balancing and flexibility role of LDES assets. They viewed BSUoS as more equitable, easier to implement, and more aligned with the nature of LDES than TNUoS, which was seen as suited to transmission infrastructure. Several stakeholders emphasised BSUoS's volumetric basis and its ability to capture locational system value. However, some raised concerns about BSUoS volatility and in-year adjustments, preferring TNUoS for its predictability and stability.

8.6 A few respondents proposed alternative mechanisms, such as a Supplier Levy, to ensure payment certainty and investor confidence. Others requested clarity on whether BSUoS or TNUoS would be treated as pass-through costs and stressed the importance of ringfencing or prioritising floor payments to mitigate under-recovery risks. Overall, the majority agreed with our minded-to position favouring BSUoS, while highlighting implementation and payment security considerations.

Our decision

8.7 We have decided to maintain our position on the use of the BSUoS framework as the mechanism for managing payment flows between LDES Projects and consumers. This approach was heavily favoured in the Consultation responses as it was seen to support the balancing and flexibility role LDES assets will play in the market.

9. End of regime arrangements

This section summarises our Consultation positions, stakeholder feedback and our decision. Detailed end of regime arrangements will be developed as part of the licencing work starting in Q3 2025. Our current position is not to have open-ended clawbacks but ensure that any end of regime arrangement will be time-bound and seek to recover floor payments paid for by consumers.

Questions

Q17. What are your views on including a residual value at the end of the cap and floor period, and how should this affect depreciation and investor returns?

Q18. What policy mechanisms should be introduced to support investability now and post regime or recovery of residual value beyond the C&F period?

What we consulted on

9.1 We consulted on how to manage LDES Projects after the C&F regime ends, particularly for long-lived assets. The default assumption was a 25-year regime with zero residual value and no floor beyond that point. However, we proposed allowing Projects to bid for longer regime durations and/or include a residual value in their bids.

9.2 We sought views on whether to introduce additional measures to protect consumers after the regime ends. These include applying a soft cap on post-regime revenues for Projects that retain significant value after receiving consumer support, and clawback mechanisms where Projects relied heavily on floor payments or had major cost overruns or delays. The Consultation emphasised that any post-regime rules should be simple, proportionate and avoid discouraging further investment, while ensuring consumers are not exposed to unfair risks.

9.3 At the Consultation stage, we did not detail any proposed post-regime rules but instead included high-level principles, which were:

a) Consumers should face similar risks across long- and short-lived Projects;

b) Post regime rules should not reintroduce investment risks the C&F regime is designed to reduce;

c) Rules should not discourage further LDES investment, including refurbishment, where that is in consumers’ interest;

d) Project lifetime returns should not be capped below the C&F regime return at floor return over the asset's full economic life.

Stakeholder responses

9.4 Most stakeholders strongly opposed introducing open ended post-regime clawback mechanisms, stating they undermine the certainty that the floor is intended to provide and would deter investment. Some stakeholders warned that clawbacks create open-ended risk and complexity, particularly for long-life assets like PSH. There was support from a broad range of stakeholders for certain repayment mechanisms to be implemented but these should be limited – time bound, event-driven (triggered only if significant floor payments were made), and applied only to revenues above the cap.

9.5 Views on soft cap were mixed. A few stakeholders supported a soft cap or repayment of floor payments post-regime to protect consumers, while most opposed enduring caps on post-regime revenues, stating they would stifle innovation and reduce incentives for continued operation. Overall, stakeholders called for simple, predictable post-regime rules that avoid reintroducing risks after the 25-year term.

Our decision

9.6 We have reviewed stakeholder feedback and while we do not intend to set policy at this stage, we would like to provide clarity on certain post-regime aspects. We have decided not to apply open ended post-regime clawbacks. Any post-regime arrangement will be time bound, not enduring, and will seek to recover received floor payments which have been paid for by consumers. This may be either through a soft cap, or reconciliation periods as seen in Window 3 of the Interconnectors.

9.7 We continue to build on our approach, and our decision will be guided by the four core principles as outlined above in paragraph 9.3.

9.8 We will not introduce detailed post-regime mechanisms at this stage. Instead, we will include high-level principles in the C&F licence for Window 1 Projects and develop more detailed arrangements as part of the licencing work commencing in Q3 2025. As stated in the Consultation, this approach provides early clarity while maintaining flexibility to reflect future market conditions and consumer outcomes.

10. Cap and floor financial model (CFFM)

This section summarises our approach to the financial model and handbook that will be used to calculate cap and floor levels for LDES Projects.

Questions

Q19. What are your views on our proposed financial model and handbook? Do you have any suggestions for simplifying it while keeping it clear and robust?

What we consulted on

10.1 We consulted on using the CFFM as the basis for setting C&F levels. The aim was to confirm that the model and its handbook were clear, robust, and flexible enough to support both administrative and competitive approaches. This consultation focused on ensuring stakeholders understood how the model works and could provide feedback on its suitability.

10.2 CFFM builds on the interconnector model but includes changes to reflect the specific features of LDES technologies. It calculates revenue levels using key building blocks as presented in the model.

Stakeholder responses

10.3 Respondents broadly supported our proposal to adapt the interconnector CFFM for LDES, with appropriate modifications. Many stakeholders stressed that the model must reflect the diverse characteristics of LDES technologies, including asset lifetimes, depreciation, and commissioning profiles. Several stakeholders requested usability improvements, such as clearer guidance, visual aids, and more intuitive interfaces. Others raised technical concerns, including unrealistic assumptions around debt service coverage, gearing, and revenue estimation.

10.4 Some respondents recommended incorporating more granular modelling, dynamic sensitivity analysis, and quarterly cashflows to better reflect Project Finance practices. There were calls to distinguish tax treatments, improve transparency, and ensure consistency across similar technologies. A few stakeholders flagged specific errors in the current model and urged Ofgem to finalise and correct it before awarding regimes.

10.5 Overall, the feedback highlighted strong support for the model’s foundation, coupled with a clear demand for clarity, refinement, and alignment with real-world financial structures.

Our response to stakeholder feedback

10.6 Following the consultation, we have made changes to address the key points raised. We are grateful to stakeholders for their constructive input:

a) We have kept input options simple and sensitivity testing features out to stay broadly aligned with the interconnector models. Projects should carry out any necessary analysis in their finance models used to raise debt and equity.

b) The model and handbook now provide clearer guidance on tax assumptions and how these can be adjusted for different Project structures.

c) We have reviewed our assumptions for the treatment of different LDES technologies and consider them fair across the range of technologies.

d) We believe that all stakeholder-identified errors have been resolved. The model has also been through extra quality checks by our independent external model auditor.

10.7 To improve usability, we have introduced clearer visual guidance in the CFFM. The inputs are colour coded into four categories:

a) Developer inputs (‘Light Yellow’);

b) Developer inputs from data submission form (DSF) (‘Rose’);

c) Ofgem default assumption (can be replaced by developer) (‘Light Blue’); and

d) Ofgem inputs (‘Blue’).

Our decision

10.8 The final CFFM and handbook, which will support consistent application of the framework and inform PAs, will be published following this decision. The handbook will provide a detailed overview of the aim, structure and functioning of the CFFM including the underlying building blocks and the content of each worksheet in the model (in terms of its inputs, calculations and outputs).

10.9 The CFFM has been updated to reflect policy changes from our Consultation position, namely the paring back of competitive elements of the bid parameters. All financial figures in the CFFM (inflation, tax, rates of return) are indicative and subject to finalisation. The CFFM will be used to determine the cap level, notional floor level and, actual cost of debt (ACOD) floor level for LDES C&F Projects.

10.10 Where Projects provide tax input data, this will be reviewed, and values may be adjusted where we conclude that the licensee is providing figures that we consider to be materially incorrect.

10.11 Projects must complete and submit a CFFM as part of their submission for the PA stage. The administrative C&F levels should be calculated based on financial parameters, proposed regime length, residual value and relevant cost data, following the LDES C&F Window 1 regime policy. Projects must use the indicative input parameters we have published as part of this Decision, alongside their own cost information consistent with data submitted in the DSF, to populate the CFFM and generate C&F levels. The completed CFFM data must be submitted to Ofgem by the PA DSF deadline.