Energy for generations

ESB Generation and Trading Response to UR Consultation for Assessment on the Need for a Regulated Operating Revenue Regime for Future Interconnection

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1. SUMMARY INFORMATION

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2. INTRODUCTION

ESB Generation and Trading (ESB GT) welcomes the opportunity to respond to the UR Consultation for the Assessment on the Need for a Regulated Operating Revenue Regime for Future Interconnection.

The consultation sets out the UR's intended approach to assess whether a regulated revenue regime similar to the Cap and Floor model in place in GB since 2014, is appropriate for the prospective 700 MW LirIC Interconnector project. If built, the project is expected to become operational in 2032 and is currently seeking to connect at Kilroot in Northern Ireland (NI) and Hunterston in Scotland.

We note that this is the first time that the UR has received a request for a regulated revenue regime from a prospective interconnector project and does not have an established procedure for assessing and approving such a regime. A Final Determination on this request is expected by the end of 2026.

In November 2024, Ofgem granted LirIC a Cap and Floor regime in principle following a Window 3 Initial Project Assessment (IPA) application. ESB GT understands that the project proposer expressed a preference for a 50:50 cost sharing mechanism that would see 50% of the costs (and risk) associated with a Cap and Floor regime award

attributed to GB consumers, with the remainder allocated to NI consumers if the current application is successful.

ESB GT believes that this consultation phase on the need for a regulated revenue regime for the LirIC project provides an excellent opportunity to ensure that the assessment procedure for new interconnection in NI is robust and protects the current and future interests of consumers.

3. ESB GT RESPONSE

Q1. Do respondents have any views regarding additional interconnection in Northern Ireland that you would like to highlight? If so, please provide details.

ESB GT strongly believes that additional interconnection between NI and the Republic of Ireland should be prioritised ahead of cross-border interconnection to alleviate the persistent problem of grid constraints. Grid congestion has driven increasing levels of non-market-based dispatch down of renewable generation which has become a marked and persistent feature in the SEM in recent years.

A revenue floor for new interconnection risks subsidizing imports into an already constrained system and exacerbating grid congestion. 700 MW of additional interconnection between NI and GB can reasonably be expected to significantly increase dispatch down given the size of the SEM, especially if it continues to be a large net importer from GB and operational constraints continue to limit exports[1] into the future.

Dispatch down threatens the business case for new projects, erodes the value of existing generation, and damages investor confidence, calling into question the viability of the government's 80% RES by 2030 target. It is vital that the impact of additional

[1] An operational constraint which limits Maximum Total System Load Rejection from Large Energy Users and Interconnector Exports to 900 MW is in place since January 2026. This new constraint is expected to restrict exports on the interconnector, with SO-SO trades used as a management tool.

interconnection is considered alongside wider investibility concerns and the broad policy framework.

Due consideration must be given to alternative policy measures to facilitate the build-out of indigenous generation, storage and demand-side response, as well as much-needed grid reinforcements. We would expect a thorough evaluation of alternative measures, and the associated impacts on costs for various market participants to be carried out prior to the proposed workstream.

Further, the UR itself acknowledges the need for research to determine the optimal level of future interconnection. Until that research is concluded we do not believe there is value in considering a regulated revenue regime for any interconnector project.

While a blanket interconnection target of 15% of installed generation capacity has been mandated at EU-level, it is unclear to what extent this level of interconnection is appropriate for the SEM as a small island system. We would also question whether interconnection is reliably able to make a comparable contribution to guarantee security of supply relative to indigenous generation.

The UR further states that their assessment will incorporate the work undertaken in cooperation with the Department for the Economy (DfE) to progress the development of interconnector policy. It is unclear why any assessment is being progressed until we receive a final decision from Government.

The completion of the second north south tie line, and other key grid reinforcement projects, have been highlighted as the most important long-term measures to reduce dispatch down. We note that the second north south tie line is only expected to become operational in 2032 after a five-year delay.

Lack of wider policy alignment risks imposing undue costs on consumers stemming from higher levels of dispatch down and weakening investment signals in NI. We would urge the UR and DfE to consider this impact, and the impact of continued delays in the

roll out of grid reinforcements, before any decision is made to approve a regulated revenue regime for additional interconnection.

Q2. Do respondents have any additional considerations they believe should be included within the step two workstream? If so, please provide details.

In addition to the position set out in response to Q1, we would urge the UR to thoroughly consider whether a 50:50 cost sharing mechanism to fund the interconnector is appropriate. We understand this will form part of the assessment.

A 50:50 cost sharing mechanism would see the costs associated with a Cap and Floor regime attributed across the NI market with less than 1 million consumers versus the GB market with close to 30 million. Under such an arrangement it is unclear that NI consumers would receive a relative quantity of 'benefits' for the risk associated with underpinning the floor of the proposed mechanism.

Further, we understand that the cost-benefit analysis for the interconnector project would consider benefits across NI and the SEM, whereas the cost of underwriting the interconnector would lie with the NI consumer alone in the form of increased network tariffs. We would welcome clarification as to intended breakdown of the cost-benefit analysis to avoid the risk that the NI consumer subsidises benefits elsewhere.

Q3. Are respondents aware of any other interconnector revenue models outside of those listed above? If so, please provide details for any other models considered to be available.

In its consultation, the UR has proposed a revenue model for new interconnection similar to Ofgem's Cap and Floor regime which has been in place since 2014.

We note that the Ofgem regime invites invitations from prospective projects by way of application window and then carries out a relative assessment to determine relative consumer benefits, deliverability, constraint impacts, and system value before deciding which projects to support. A 'Marginal Additional' assessment was used by Ofgem to inform its decision to award a Cap and Floor regime to the LirIC interconnector.

We believe that the current approach, whereby the Regulator assesses projects on a first-come first-serve basis is bound to yield suboptimal results. Unlike in the Capacity Mechanism or planned renewable auctions there will be no price discovery to determine the most suitable interconnector projects, necessitating a greater level of scrutiny to avoid imposing undue costs on consumers.

At a minimum, a cross-jurisdictional approach to assessing prospective interconnector projects should be considered to avoid siloed decision-making, which may end up imposing higher costs on consumers in both jurisdictions.

ESB GT acknowledges the financeability benefit associated with a similar Cap and Floor mechanisms on both sides of the interconnector. UR has provisionally suggested it will consider a 25-year Cap and Floor regime to mirror the GB model, pending the outcome of the needs assessment.

We note that any interconnector will be competing with generation that is limited to a 10 or 15-year contract through the Capacity Mechanism or renewables subsidy scheme, respectively, creating a divergence in risk profiles. ESB GT is of the view that any regulatory intervention in the market should create a level playing field for all participants looking to compete. We believe there may therefore be reason to review the length of a Cap and Floor mechanism.

Q4. Do respondents agree with the criteria and principles to be applied during this assessment? If not, please provide details of other criteria/principles that may also warrant consideration.

Our response to Q1 and Q2 identifies a clear need for policy alignment and a comprehensive appraisal of alternative measures ahead of the proposed workstream.

We would nevertheless agree that the broad assessment criteria set out in the consultation, covering (i) market modelling, (ii) system impact, (iii) cost and technical assessment and (iv) deliverability, appear reasonable with the following recommendations:

1) Market Modelling

We would expect the market modelling to include a wide range of scenarios and system conditions to understand the impact of incremental interconnection on prices and constraints.

There is a clear need to ensure that the model does not differ substantially in its assumptions versus the equivalent GB model and reflects a realistic outlook for the build out of renewables in both jurisdictions over the study period, and the associated impact on spreads. We would urge the UR to investigate the methods, inputs and assumptions which informed the two studies carried out ARUP and LCP Delta within the context of Ofgem's Initial Project Assessment.

We would further expect the assessment to be aligned with the latest available ENTSO-E Guidelines for Cost Benefit Analysis of Grid Development Projects.

2) Systems impact

A full range of system impacts (dispatch down and system operability) should be included in the modelling to ensure that all costs and benefits are captured.

ESB GT is currently engaging on SONI's Dispatch Down Draft Action Plan, an urgent and essential piece of work. It is important that the UR and SONI ensure consistency and transparency in their approach to modelling the systems impact of the additional interconnector and consider all inputs considered within the wider Dispatch Down Action Plan project.

We are awaiting the first auction of the NI Renewable Electricity Price Guarantee (REPG), expected in 2027 pending legislative approval. The auction is expected to provide full compensation for dispatch down to contracted projects (pending a resolution of the Court of Justice of the European Union (CJEU) case on the interpretation of Article 13(7) of Electricity Regulation (EU) 2019/943). We would expect the cost-benefit analysis to consider divergent outcomes in the CJEU case.

SEMC Imperfections Charges for October 2025 – September 2026 included rising consumer costs linked to dispatch down (including potential Article 13(7) costs) and dynamic stability requirements. All impacts on system operability should also be explicitly modelled and qualitatively assessed to ensure the full range of costs is captured for consideration against the 'beneficial' impact on the wholesale price.

It would be reasonable to assume that the cost of procuring balancing and ancillary services increases steadily with higher levels of interconnection, including balancing, voltage support, frequency response, inertia and head room and foot room. This is primarily due to the need for additional thermal synchronous generation to provide flexibility, although this should be partially offset by an increase in synchronous condenser capacity.

Conversely, lower load factors and an increased number of starts for thermal generation requires those generators to recover the missing money in other markets.

3) Cost and technical assessment

ESB GT has previously raised concerns regarding the impact of new interconnection on generators near the proposed connection point, particularly in relation to sub-synchronous resonance (SSR), the impact of new interconnection on the ramp rate functionality of existing interconnectors and the consequential impact on the market and system efficiency. This is particularly important where system limitations on aggregate interconnector ramp rates undermine the ability of interconnectors to adhere to their market scheduled quantities thereby eroding the convergency value between markets of the interconnectors to the customer.

The UR should ensure technical aspects of the project submission adequately address these issues. Any impact on incumbent generators / interconnectors or system operability, including the dimensioning of system service requirements, must be made available to ensure full transparency in the assessment.

Q5. Do respondents support the proposed parallel work to be commenced in Q3 2026 regarding the development of a regulated operating revenue regime framework? If not, please provide supporting details

As stated in response to the previous questions, in the absence of wider policy alignment and a DfE decision on interconnector policy we would urge the UR to focus its resources in other areas, before commencing work on a framework for a regulated operating revenue regime, which may risk pre-empting the outcome of the current assessment.

We reiterate that grid reinforcement and measures to reduce dispatch down should be prioritised by the Regulators to deliver concrete, long-term benefits to NI consumers.