Decision

RIIO-2 Re-opener Applications 2025 Final Determinations – ED Annex

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This document sets out our Final Determinations following our assessment of re-opener applications submitted by Distribution Network Operators (DNOs) in January 2025. Electricity North West (ENWL)[1] submitted projects under SpC 3.2 Part K: Load Related Expenditure (LRE) Re-opener and Scottish and Southern Electricity Networks (SSEN)[2] submitted projects under Special Condition (SpC) 3.2 Part O: Hebrides and Orkney Re-opener (HO_t). We[3] consulted on our Draft Determinations between 18 July 2025 and 27 August 2025 and asked stakeholders a number of questions. We received three responses from ENWL, SSEN and National Grid Electricity Distribution (NGED) on LRE Re-opener and four responses, one from SSEN, Scotch Whisky Association, Argyll and Bute Council, and the Member of Parliament (MP) for Argyll Bute and South Lochaber on Hebrides and Orkney Re-opener. Our Final Determinations on the allowances for 2025 HOWSUM re-opener are for £77.153m for RIIO ED2 and for ENWL's LRE re-opener are £150.747m for RIIO ED2.

The statutory Licence Modification for the LRE Re-opener published will be published shortly after our decision and will set out the proposed licence modifications reflecting these final determinations. The direction for the Hebrides and Orkney re-opener published alongside our decision will set out the proposed licence modifications reflecting these final determinations. We also intend to consult on licence modifications to allow us to set Price Control Deliverables (PCDs) for both mechanisms.

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[1] Following its acquisition by Iberdrola, Electricity North West Limited (ENWL) was integrated into the ScottishPower group, and in August 2025, it adopted the trading name SP Electricity North West.

[2] The submission was from SSEN Distribution (SSEN) the trading name of Scottish Hydro Electrical Power Distribution plc (SSEH) and Southern Electric Power Distribution plc (SSES). The projects and responses were submitted on behalf of SSEH and SSES.

[3] The terms 'the Authority', 'Ofgem', 'we' and 'us' are used interchangeably in this document. The Authority is the Gas and Electricity Markets Authority. Ofgem is the office of the Authority.

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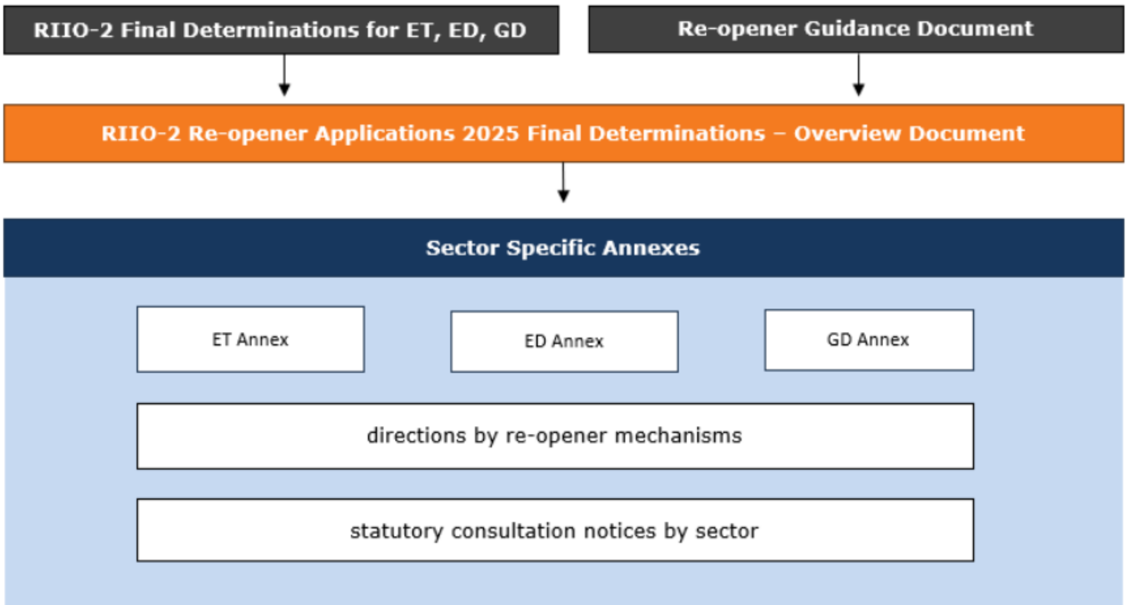
Contents

1. Introduction

1.1 This document is one of the Annexes published alongside the RIIO-2 Re-opener Applications 2025 Final Determinations. It focuses on the re-opener mechanisms and the Final Determination of projects submitted in the ED sector. Please refer to the RIIO-2 Re-opener Applications 2025 Final Determination – Overview Document for general information including decision making process, stages, etc.

Figure ED1: Navigating our Final Determinations



Hebrides and Orkney Re-opener

1.2 When we[4] made our RIIO-ED2 Final Determinations (ED2 FDs) in November 2022, we remained unclear about customer needs for proposed projects in Hebrides and Orkney[5] due to the possible impact of outstanding third-party decisions that were likely to affect demand.

1.3 We agreed with SSEN's proposal to utilise a re-opener that could be triggered after SSEN had finalised a whole system review of needs that takes into account these external decisions.[6] As such, we provided development funding in ED2 FDs and introduced the Hebrides and Orkney Re-opener for SSEN to request additional funding for the costs associated with the outcomes of additional whole system

[4] The terms 'the Authority', 'Ofgem', 'we' and 'us' are used interchangeably in this document. The Authority is the Gas and Electricity Markets Authority. Ofgem is the office of the Authority.

[5] For a list of the projects, see 3.2.105(a) in Appendix 1.

[6] at paragraph 4.6

analysis in the Scottish Islands to contribute to Net Zero Carbon Targets and ensure long-term security of supply to the Hebrides and Orkney islands in Scotland.

Load Related Expenditure (LRE) Re-opener

1.4 In the RIIO-ED2 FDs, we provided LRE ex ante allowances to enable up-front investment to support Net Zero where there is high confidence in its needs case and to allow DNOs to respond quickly to future changes in demand. We also established an LRE Re-opener for the DNOs to request additional funding if required to cater for the uncertainty in LRE activities as described in SpC 3.2.75 (as listed in Appendix 2).

What did we consult on?

1.5 In January 2025, SSEN applied to Ofgem under SpC 3.2 Part O (Hebrides and Orkney re-opener) to add additional allowances for £158.590m for four separate projects as well as requests for additional indirect and supporting analysis funding. SP ENW applied for an additional allowance of £201.6m under SpC 3.2 Part K (LRE Re-opener) into its RIIO-2 price control framework.

1.6 Following these submissions in January 2025, the licensees also provided additional information to us through a combination of bilateral meetings and responses to Supplementary Question (SQ).

1.7 We considered each proposal and the relevant justification for the funding requested in accordance with our principal objective and statutory duties. In line with the Re-opener Guidance and Application Requirement Document, our assessment covered the following three areas for each project:

- the needs case.
- the options assessment and the justification for the proposed project.
- the efficient costs for the proposed project.

1.8 We considered all relevant information in formulating our Draft Determinations including the levels of additional allowances, if any, that should be provided to each licensee to undertake the relevant projects.

1.9 We consulted on our Draft Determinations between 18 July 2025 and 27 August 2025, as well as drafts of the directions or licence modifications that would be used to implement the Draft Determinations. We received three responses from ENWL, SSEN and NGED under the LRE re-opener and a total of four responses from SSEN, Scotch Whisky Association, Argyll and Bute Council, and the Member of Parliament (MP) for Argyll Bute and South Lochaber regarding the projects under the Hebrides and Orkney re-opener.

Purpose of this document

1.10 This document summarises the consultation responses received from stakeholders, and an explanation of the changes made, if any, to our Draft Determination positions since the consultation. It also sets out our Final Determinations for these applications submitted under the re-opener mechanisms listed in Table ED1 below.

Table ED1: ED re-opener mechanisms subject to this decision

Reopener Mechanism	Special Licence Condition
LRE Reopener	3.2 Part K
Hebrides and Orkney Reopener	3.2 Part O

1.11 Alongside this decision, we will shortly publish a direction to amend the licence of SSEH to give effect to the Hebrides and Orkney projects approved in our FDs.

1.12 We will also publish shortly the consultation on our proposed modifications to ENWL's electricity distribution licence to give effect to our FDs on LRE re-opener.

Related publications

1.13 This document is intended to be read alongside:

- Draft Determinations on RIIO-2 re-opener applications 2025: Electricity Transmission, Electricity Distribution and Gas Distribution | Ofgem
- RIIO-ED2 Re-opener Guidance and Application Requirements Document

1.14 LRE re-opener

- Special Conditions (SpC 3.2 Part K in particular) of the electricity distribution licence held ENWL
- re-opener submission documents on SP ENW's website

1.15 Hebrides and Orkney application

- RIIO-ED2 SSEN Final Determination (FD)
- SpCs (and SpC 3.2 Parts O and R in particular) of the Licence.
- Re-opener submission documents on SSEN's website.

Summary of our Final Determinations

1.16 Table ED2 below summaries our Draft and Final Determinations for the ED re-openers covered in this annex. Chapters 2 and 3 discusses these in greater detail.

Table ED2: Summary of our ED Draft and Final Determinations

Network	Company Forecast costs (£m)	Ofgem's DD - Allowance (£m)	Ofgem's Adjustment from DD to FD (£m)	Ofgem's FD allowances (£m)
ENWL	201.600	93.105	+57.642	150.747
SSEH	158.590	7.890	+69.263	77.153

2. Load Related Expenditure Re-opener

Summary of our Draft and Final Determinations

2.1 Table 3 below highlights summaries of our Draft and Final Determinations.

Table ED3: Summary of LRE Re-opener Draft and Final Determinations (£m, 2020/21 prices)

Network	Company Requested Forecast costs	Ofgem’s DD Allowances	Ofgem’s Adjustment from DD to FD	Ofgem’s FD allowances
ENWL	201.600	93.105	+57.642	150.747

Our Draft Determinations

2.2 In the 2025 LRE Re-opener submissions, ENWL made a request for additional allowances of £201.6m - as listed in Table ED3. We assessed these proposals, and in our Draft Determinations:

- proposed to accept the needs case and optioneering of all proposals submitted under the Engineering Justification Papers (EJPs) except the proposed investment for electric vehicle charge points (EVCPs) at the Motorway Service Areas (MSAs), A-road Service Stations (ARSS) and bus depots.
- proposed to reject ENWL’s current funding request related to reinforcement for, what it refers to as, the “opportunistic upsizing of transformers” and “splitting of HV feeder networks with more than 2,500 customers”. Instead, these investments should be considered through the volume drivers and associated review.
- Proposed to provide additional funding at £93.105m in addition to the ex ante ED2 funding for various cost categories as summarised in the table ED4 below.
- Proposed to separately review at a later date the proposed licence modifications related to Net to Gross adjustment for LRE.

Table ED4: Ofgem's Draft Determinations

Regulatory reporting table	Cost Category	Model Costs for ENWL LRE Plan (£m)	Ex ante Funding in ED2 (£m)	Ofgem's DD (£m)
CV1	Primary reinforcement	104.938	44.500	60.438
CV2	Secondary reinforcement	3.900	6.000	-2.100
CV3	Fault level reinforcement	19.490	26.100	-6.610
CV4	New Transmission Capacity Charges	-	-	-
C2	Connections	78.177*	36.800	41.377
	Load Related Strategic Investment	-	-	-
	Total	**206.505**	**113.400**	**93.105**

* with non-Price Control Adjustment (NCPA) of £8.7m (at the same level of RIIO-ED2 FDs)

Responses to our Draft Determinations

2.3 We received three responses, one each from ENWL, SSEN and NGED. We have published the non-confidential parts of these consultation responses.

<u>Needs Cases and Optioneering</u>

2.4 ENWL agreed with our assessment of the needs cases and optioneering for its respective EJPs except:

(i) <u>MSAs, ARSS and bus depots:</u> in ENWL's view the assessment did not adequately consider how the capacity may be utilised and that the capacity created support the needs of multiple customers and therefore should be classed as reinforcement.

(ii) <u>Secondary reinforcement:</u> ENWL disagreed with the exclusion of two secondary reinforcement programmes (opportunistic upsizing of transformers and splitting HV feeder networks).

2.5 NGED agreed that current price control would exclude funding on MSAs but requested clearer direction to ensure necessary works can proceed. It disagreed with the proposed reinforcement to ARSS being classed as sole use and charged to the connecting customer. NGED suggested that this should be paid for by energy consumers through Distribution Use of System (DUoS) charges on bills.

2.6 SSEN is in broad agreement with Ofgem's assessment on the MSAs, but considers the assessment to have identified a gap in the policy framework that should be addressed. In SSEN's view there is no obvious funding mechanism in place to deal with the reinforcement for the EVCPs.

Cost Assessment

2.7 ENWL agreed with the use of disaggregated benchmark modelling as part of the cost assessment process, but it disagreed with some aspects of our modelling. . ENWL made some suggestions to recognise the importance of benchmarking in establishing efficient allowances and address the inherent challenges with undertaking this for reopeners. The suggestions include:

(i) Incorporate the impact of Access SCR post-model.

(ii) Reprofile input volumes to better align cost and output timing or separate two atypical projects (Harker and Cumbria Ring) from CV1 cost benchmarking.

(iii) Adjust disallowed EJPs within the CV1 cost model rather than post-model (with input volumes of associated EJPs reprofiled similar to suggestion (ii) above).

(iv) A binary approach for CV2 and CV3 to set the re-opener allowance in these two areas to zero if the respective modelled costs are lower than the ED2 baseline allowance, and at the modelled level if higher than the ED2 baseline allowance.

(v) Account for the Totex model (by a scaler-based adjustment). This suggestion is to align with the ED2 baseline setting where final allowances were a combination of the outputs from two models, a disaggregated model and a totex model. Our DD approach was to utilise only the disaggregated model.

2.8 NGED disagreed with the approach of solely using disaggregated cost models from the ED2 FDs. It considered we should take account of all latest evidence submitted, especially when there have been significant price movements since the submission of ED2 business plans. NGED also pointed out that ED2 allowances were set using Totex models alongside the disaggregated models, and were also set up to operate alongside mechanisms such as Real Price Effects (RPEs).

2.9 SSEN disagreed with the approach of using backward looking costs as a measure of cost efficiency. SSEN commented that the disaggregated cost models are not reflective of current market rates and we should rely on market tendered costs and address the significant changes and industry growth.

Other Views

2.10 NGED and ENWL also provided the following views to the proposed licence modification on the net to gross adjustment to LRE:

(i) NGED: fully supported a review of net to gross calculations but would welcome clarity from Ofgem on the scope and timeframes for these reviews.

(ii) ENWL: requested Ofgem to commit to a process and timescale by which the changes can be reviewed at a later date, and requested that this date is well in advance of the end of ED2.

2.11 NGED and ENWL also provided the following views to the review of the ED secondary reinforcement volume drivers in year 3 of the price control period:

(i) NGED: supports a full review of the caps and welcomes clarity from Ofgem on timeframes.

(ii) ENWL: suggests the two programmes should remain in the re-opener unless there is clear assurance that the Year 3 review will fully and appropriately incorporate them. It requests a clear roadmap and timeline outlining how the review will assess the need and enablement of the two programmes.

Our Final Determinations

Need Case & Optioneering

EVCP Proposals at MSAs

2.12 We have reviewed the further justification provided by ENWL regarding the proposed investment for EVCPs at MSAs. ENWL proposes constructing a distribution substation at MSA sites to support multiple EVCP connections. The investment need is triggered by an initial EVCP connection, with several additional connections anticipated. Given the expected volume of connections, ENWL considered the investment is network reinforcement rather than extension assets. The difference from customer and energy consumer perspectives is that network re-enforcement are paid for by consumers through their bills, whereas extension assets are typically paid for solely by the connecting customer(s).

2.13 We have carefully considered the additional arguments presented by ENWL advocating for these assets to be classified as reinforcement assets and the views from other respondents. However, after thorough review on the responses and the Distribution Code (in particular P2/8 on distribution security of supply) , our position remains unchanged from the DDs that we consider it appropriate to classify these assets as extension assets. Our updated view on ENWL's proposal is as follows:

- ENWL's proposed design, comprising a single-circuit EHV connection with HV interconnection, is inefficient and does not provide P2 compliance beyond the initially accepted connections. The HV interconnection is also ineffective in reinforcing the surrounding demand groups, as capacity constraints are primarily due to long HV feeders. Addressing these constraints would require reinforcement of the existing network, which could eliminate the need for the proposed HV interconnection altogether. As such, the HV interconnection appears to be a design choice aimed at socialising costs, rather than delivering efficient reinforcement.

- A more efficient long-term solution would be to construct a double-circuit EHV connection without interconnection to the existing network. However, under current connection charging rules, this would be classified as extension assets, regardless of the number of future connections. These works should therefore be funded by the first connecting customer and subsequently socialised as additional customers connect.

- Extension assets must be agreed upon and fully paid for by the initial connecting customer. There is no scope for overrating in anticipation of future connections unless the first customer explicitly agrees and funds the additional capacity.

- Therefore, in the case of MSAs, and in line with current connection charging arrangements, a primary substation at an MSA site can only materialise if a connecting customer requests and pays for it.

2.14 We therefore maintain the position set out in our DDs and confirm our decision to reject the EJP and the associated funding for EVCPs at MSAs. We note from the consultation responses that both NGED and SSEN support our proposal to exclude EVCPs at MSAs from the price control.

2.15 We excluded funding for EVCPs at MSAs from the LRE re-opener on the basis of the user-pay principle, specifically, whether these assets should be classified as connection assets and funded by the connecting customers.

<u>EVCP Proposals at A-road Service Stations</u>

2.16 We have reviewed the additional information provided by ENWL regarding the two configurations in its EVCP proposal at ARSS. These two configurations involve either (1) installing a new HV feeder or (2) looping into the existing HV network. ENWL's proposal assumes a mixture of these options being applied across the relevant sites.

2.17 We note NGED's response disagrees with our proposal to classify the proposed reinforcement to ARSS as customer funded, suggesting that, where interconnecting to provide security of supply, the longest leg of the two circuits should be funded through Distribution Use of System (DUoS) charges. We agree with NGED in principle. There are two elements to the proposed investment, the cost of the extension assets (the minimum need to connect the customers) and reinforcement assets (additionally needed in order to maintain security of supply). Only the second element should be DUoS funded. Using the information available in ENWL's submission, we have therefore decided to award partial funding to reflect an estimated proportion of costs that should be classified as reinforcement.

2.18 We have revised our DDs position and included £4.716m of funding in our FDs for the EVCPs at ARSS.

<u>EVCP Proposals at bus depots</u>

2.19 We have reviewed the additional information provided by ENWL regarding the EVCP proposal at bus depots. With ENWL confirming that the sole-use assets will be charged directly to the bus depots, we consider that, in line with charging practices, the funding request related to reinforcement of the existing network should be socialised.

2.20 As a result, we have revised our DDs position and included £0.800m of funding in our FDs.

<u>Secondary reinforcement programme</u>

2.21 We have reviewed the additional information provided by ENWL regarding the two secondary reinforcement programmes: "opportunistic upsizing of transformers" and "splitting of HV feeder networks with more than 2,500 customers." We maintain the views set out in our DDs that the issues raised should be considered in a broader context and with all DNOs through the Year 3 review of the volume driver mechanisms. Accordingly, we confirm our decision to reject ENWL's current funding request related to these programmes. Instead, these investments should be progressed through the volume driver mechanisms and its associated review process.

<u>Cost Assessment</u>

2.22 In determining the efficient allowance for the LRE re-opener within our DDs, we established the following guiding principles:

- The LRE re-opener is intended to provide DNOs with a mechanism to request additional funding for newly identified requirements. It is not designed to revisit or revise decisions made in the ED2 FDs, including but not limited to established benchmarks.

- The cost assessment methodology should, as far as practicable, align with the approach adopted in the ED2 FDs to ensure consistency in determining efficient costs.

- The assessment framework should be applied consistently and be replicable across all DNO applications, regardless of the timing of the re-opener submission.

2.23 We have assessed ENWL's suggestions in relation to the cost assessment approach and the level of allowance for its LRE re-opener application proposed in our DDs. Our views are summarised in paragraph 2.24 onwards below.

Adjustment for Access SCR

2.24 We agree with ENWL's observation that the impact of Access SCR was not reflected in the disaggregated cost models of ED2 FDs, and that a post model adjustment was applied in ED2 FDs. Consequently, applying the benchmark unit rates from the ED2 FDs cost models would result in an insufficient allowance for C2 Connections, failing to account for the additional costs arising from post Access SCR connection requests. Therefore, in our Final Determinations for this re-opener we have applied an additional adjustment to account for Access SCR, consistent with the approach adopted in the ED2 FDs.

2.25 We have reviewed ENWL's methodology for determining the level of adjustment related to the Access SCR, including the proposed allowance adjustment. In general, we agree with the use of the proportion of the previous Access SCR adjustment relative to the ED2 FDs totex as a reference point. However, we have capped the level of adjustment at the original amount requested under C2. This is because the re-opener submission should have already accounted for the impact of Access SCR.

2.26 In our DDs, we reduced the C2 allowance by £15.223m, based on the disaggregated cost model. This amount is lower than ENWL's estimate of the proposed Access SCR adjustment. Therefore, we will set the Access SCR adjustment for ENWL under the LRE re-opener at £15.223m, which effectively represents full acceptance of the proposed C2 cost of £93.4m.

Reprofile input volumes for major projects

2.27 We have assessed ENWL's suggestions to either exclude two major projects, Harker and Cumbria Ring, from CV1 cost benchmarking for conducting bespoke cost assessments, or to reprofile their input volumes within ED2 period. These proposals aim to address the timing mismatch between costs and outputs, where the majority of costs are expected to be incurred during the ED2 period, while the associated outputs will only be delivered post-ED2.

2.28 We consider it appropriate to retain the Harker and Cumbria Ring projects within the CV1 cost benchmarking model to ensure that efficient project costs are determined in line with the established methodology. The timing mismatch between costs and outputs can be addressed by reprofiling the relevant outputs into the ED2 period. Furthermore, we believe that this approach to volume reprofiling should be consistently applied to other large projects where outputs are delivered shortly after the ED2 period.

Adjustment to Rejected EJPs

2.29 In our DDs, we applied a proportional adjustment to exclude funding for rejected EJPs immediately following the CV1 cost benchmarking exercise. We agree with ENWL that the appropriate approach is to exclude rejected EJPs as a pre-modelling adjustment, i.e. removing the relevant cost and volume data for the rejected EJPs from the cost models.

2.30 We have re-run the CV1 cost benchmarking model, incorporating the changes outlined in paragraphs 2.27 to 2.29 above. The resulting modelled cost for ENWL's primary reinforcement is £140.107m, which is £35.170m higher than that in the DDs.

Binary approach for CV2 and CV3

2.31 In our DDs, the values for CV2 and CV3 from the cost benchmarking model were lower than the equivalent baseline allowances awarded, implying a negative adjustment. Our assessment considers the entire LRE plan for the ED2 period, and we have set a total allowance accordingly. No baseline funding has been clawed back, even though the values under CV2 and CV3 in the re-opener are negative. We therefore do not believe the proposed binary approach for CV2 and CV3 is in the best interest of consumers.

2.32 Importantly, the negative CV2 value arises because funding for two secondary reinforcement programmes has been excluded and instead considered under the volume driver mechanisms. If these programmes subsequently receive funding through volume drivers, applying ENWL's proposal would therefore likely result in partial double funding.

Account for the Totex model

2.33 In our DDs, we used disaggregated cost benchmarking models to assess the efficient cost of ENWL's LRE re-opener submission. We did not replicate the full totex benchmarking model used in the ED2 FDs, as we do not have access to the same level of detailed information in a re-opener application. We also consider that incorporating the totex model would likely have a limited impact, and we recognise that the cost efficiency imposed by the disaggregated models is generally more stringent.

2.34 We have reviewed ENWL's proposed methodology for estimating a totex adjustment, which is an incremental method utilising the ED2 FD results to develop a scaler-based approach. We agree that, assuming the additional allowance does not materially shift the relative positions of the totex and disaggregated cost benchmarks, this incremental method provides a sufficiently accurate estimate of overall results had a full FD totex and disaggregated benchmarking exercise been possible.

2.35 We calculated the results from the disaggregated cost benchmarking models and applied the proposed scaler to derive the corresponding totex adjustment. This results in an increase to the total re-opener allowance of £1.734m.

Real Price Effect

2.36 We have considered the consultation responses from SSEN and NGED regarding the ED2 benchmark unit costs, which they argue do not reflect current market prices due to significant market growth.

2.37 We recognise that baseline funding is designed to operate alongside the application of Real Price Effects (RPEs), which address price movements within the price control period. Typically, funding provided through the re-opener mechanism is not subject to RPEs, as most re-opener applications undergo bespoke cost assessments.

2.38 We have carefully considered the responses regarding recent market movements, rising costs, and the potential application of the RPE mechanism to funding allowed under the LRE re-opener. However, we do not believe it would be in the best interests of consumers or other stakeholders to apply the RPE mechanism to re-opener allowances or to change RIIO-ED2 mid-period.

2.39 RPE re-opener applications should be treated consistently with all other re-opener mechanisms in line with our ED2 FDs on price movement and uncertainty under RIIO-ED2. Therefore, it would not be appropriate to apply the RPE mechanism to the LRE re-opener within RIIO-ED2. Instead, we consider that any cost fluctuations should be more appropriately shared between licensees and consumers through the Totex Incentive Mechanism (TIM).

Others

Net to Gross adjustment to LRE

2.40 We have considered the consultation responses from NGED and ENWL regarding the review of the Net-to-Gross adjustment to LRE. We maintain the position set out in our DDs that the issues raised should be considered in a broader context and in collaboration with all DNOs. We will engage separately with all DNOs to discuss the proposal further.

2.41 In summary, our FDs on the allowance for ENWL LRE re-opener are summarised below.

Table ED5: Ofgem's Final Determinations on the LRE Re-opener

Regulatory reporting table	Cost Category	Ofgem's DD (£m)	Adjustment from DD to FD (£m)	Ofgem's FD (£m)
CV1	Primary reinforcement	60.438	35.170	95.607
CV2	Secondary reinforcement	-2.100	5.516	3.416
CV3	Fault level reinforcement	-6.610	-	-6.610
CV4	New Transmission Capacity Charges	-	-	-
C2	Connections	41.377	-	41.377
	Load Related Strategic Investment	-	-	-
	Access SCR Adjustment	-	15.223	15.223
	Totex Adjustment	-	1.734	1.734
	Total	**93.105**	**57.642**	**150.747**

3. Hebrides and Orkney Re-opener

Summary of our Draft and Final Determinations

3.1 Table ED6 below highlights summaries of our Draft and Final Determinations.

Table ED6: Summary of Hebrides and Orkney Re-opener Projects RIIO-ED2 Draft and Final Determinations (£m, 2020/21 prices)

Project/ Cost category	Company requested - Forecast costs (£m)	Ofgem's DD - Cost adjustment (£m)	Ofgem's DD - Allowances (£m)	Ofgem's Adjustment from DD to FD (£m)	Ofgem's FD – Allowances (£m)
Islay - Jura	104.01	-104.01	-	+34.116	34.116
Orkney	17.04	-14.580	2.460	+12.987	15.447
Outer Hebrides and Skye	24.62	-21.570	3.050	+13.960	17.010
Mull, Coll and Tiree	2.07	-0.910	1.160	-	1.160
HOWSUM 2024 application - Closely Associated Indirect (CAI) costs	9.49	-9.49	-	+8.189	8.189
Whole system analysis adjustment	1.36	-0.130	1.230	-	1.230
Total	**158.590**	**-150.700**	**7.890**	**+69.263**	**77.153**

Our Draft Determinations

3.2 In our DDs[7] we set out the reasons why we did not believe SSEN's proposals optimised the opportunity for island communities and consumers. We explained that we would consider any further evidence that SSEN provides to justify its specific proposals related to Islay-Jura and Orkney, and that we may revise our assessments should the evidence provided be sufficiently strong.

[7] RIIO-2-Re-opener-Applications-2025-Draft-Determinations–ED-Annex.pdf

3.3 We proposed to reject SSEN's request for additional funding for indirect costs and whole system analysis as these were considered covered by existing RIIO-ED2 allowances and deemed business-as-usual activities.

3.4 We proposed to support £7.890m to support investment and option development for island network solutions, with future allowances adjusted to prevent double funding as it was linked directly to the solutions for Islay-Jura, Orkney, Outer Hebrides and Skye, Mull, Coll and Tiree.

3.5 During the consultation period, we maintained regular engagement with SSEN, including weekly bilateral discussions to help ensure any additional supporting evidence that SSEN provided would be sufficient to enable us to carry out the necessary assessments of its proposals.

3.6 All additional evidence submitted by SSEN and other stakeholders during that period has been carefully considered and reflected in our Final Determinations.

Responses to our Draft Determinations

3.7 We received four responses, from SSEN, the Scotch Whisky Association (SWA), a representative of a local city council and a local Member of Parliament.

3.8 All respondents stated that the proposed funding allowance of £7.890m will be insufficient to deliver the required infrastructure in the region. All respondents expressed support for SSEN's proposals, emphasising the need for urgent works in the region, and that electrification is needed for the Scotch whisky sector and for wider economic development.

3.9 Respondents also highlighted the Scottish Government and Scottish Environmental Protection Agency (SEPA) environmental targets, noting that continued reliance on Distributed Embedded Generation (DEG) conflicts with the new targets as SSEN stated that "existing DEG cannot be run on a planned basis beyond 2033, and on an unplanned basis beyond 2039."

3.10 The SWA argued that decarbonising distilleries is a top priority and distillers need certainty to enable them to plan and invest for the transition away from fossil fuels.

SSEN's response:

3.11 The following paragraphs (3.12 to 3.20) explain the further evidence and arguments that SSEN provided to justify its proposals.

<u>Islay – Jura</u>

3.12 In response to our recommendations in the DDs on further analysis to be done regarding Islay-Jura optioneering, SSEN recommended **Option 7** (Install 3 new

33kV circuits to Islay (one from BAT Wind I and one from BAT Wind III and one from Port Ann GSP), and install a second Islay – Jura submarine cable to augment the existing Islay-Jura circuit for the Islay-Jura network), as the most cost-effective and flexible solution under current demand uncertainty. **Option 7** allowed staged delivery before ED3, met current forecasts, and retained flexibility for future upgrades, delivering N-2 resilience from 2034 onward and aligning with Scottish Government regulations and SSEN's Resilience Policy. The full updated list of options considered is available in Appendix 3.

3.13 SSEN provided information that since January 2019, there have been various subsea cable faults in the SHEPD area and an extended outage duration was assumed in sensitivity analysis. SSEN's restoration approach remains unchanged, prioritising supply security although diesel generation can maintain service during outages, it adds cost and emissions, making these timescales relevant going forward. SSEN also argued raising cable voltages or sizes would delay the project due to needing specific type tests, which require manufacturer samples and factory scheduling.

3.14 SSEN stated that DEG is not a feasible long-term resilience solution for Scottish islands due to inadequate capacity, high emissions, and operational costs of existing infrastructure like Bowmore station. Recent SSEN assessments found insufficient local resources to meet resilience needs with third-party flexibility by 2033. Therefore, SSEN proposes adding a fourth subsea cable in the early 2030s as part of the ED3 business plan, while continuing to assess alternative options.

Orkney

3.15 Following updated optioneering as referenced in our DDs, SSEN's original preferred 66kV solution, which will initially operate at 33kV, continues to be its preferred option. **Option 7A** involves two stages, the first stage is to install 57km 66kV Thurso South - South Ronaldsay via John Groats between 2024-2028 (running at 33kV) and the second stage is to upgrade the PFW and PFE circuits to be running at 66kV between 2029-2032 and retain the use of PFE3. This is SSEN's preferred option because, compared to other options considered, it offers the strongest or similar whole life net present value across sensitivity analyses. A full list of options is in Appendix 4.

3.16 With a projected capacity shortfall of 14MW on Orkney by 2033 during peak demand, SSEN recommended ongoing collaboration with SSEN Transmission to consider the feasibility and delivery of a primary 132kV circuit, with further optioneering to be incorporated into ED3 planning.

3.17 SSEN asserted that N-2 resilience is crucial for Orkney given its heavy reliance on electricity for heating, transportation (including ferries), and economic activity, arguing that the significance of a secure power supply cannot be fully captured in cost-benefit analysis alone and must be supplemented by qualitative evidence.

3.18 SSEN maintains that **Option 7A** offers the optimal balance of resilience, capacity, and carbon impact, whereas 132kV alternatives would require much higher capital spending without proportional benefits. Current third-party flexibility resources are also seen as inadequate to satisfy future resilience needs, with any successful alternative necessitating major expansion and integration efforts. Submarine cable works for the Thurso–South Ronaldsay route are scheduled for summer 2028 to facilitate type testing of the 66kV cable, though such testing is manufacturer-specific and may need to be repeated if suppliers change.

<u>Additional Costs Assessment</u>

3.19 These following points were made in addition:

- SSEN agreed with the proposed funding to be approved for development costs in our DDs.
- Additional correspondence between Ofgem and SSEN had been provided to argue that DEG costs for additional transmission outages fall within the scope of the HOWSUM mechanism for cost recovery.
- SSEN reiterated that it requires funding for standard project risk and extraordinary project risk so that it does not bear disproportionate delivery risk or risks of operating in these areas and conditions.
- Supporting information was provided to argue that indirect costs are best recovered under the January 2025 re-opener, as these costs fall outside the scope of the current HOWSUM Development Funding definition. It further notes that Scottish island projects incur elevated Closely Associated Indirects (CAI) costs but SSEN stated it seeks funding within existing regulatory frameworks to ensure equitable treatment of strategic projects and prevent the creation of inappropriate incentives.

Our Final Determinations

3.20 SSEN provided the additional information that we stated in our Draft Determinations we would need to properly assess its proposals. SSEN's case for additional funding is now much stronger, and as a result our Final Determinations see a significant increase in allowances compared to Draft Determinations. Our Final Determinations is to approve total additional RIIO-ED2 allowances of £77.153m, an increase of £69.263m on our Draft Determinations. The rationale for this decision is explained below.

<u>Islay-Jura</u>

3.21 We have reviewed SSEN's revised list of options and supporting evidence and we have consequently changed our assessment. Our view, now, is that **Option 3A** which includes the installation of an auto-close scheme at Port Ellen with a 33kV substation, the installation of two 66kV circuits from Carradale to Port Ellen, one 66kV from Port Ann - Knocklearach, as well as reinforcing the Bowmore – Knocklearach (1&2) and Bowmore - Port Ellen (1&2) circuits, is the most efficient and economical solution for Islay- Jura.

3.22 We recognise that **Option 7** meets SSEN's central planning scenario (half of distilleries decarbonise via electrification) at lower cost when compared to **Option 3A** and can be augmented with a 5th 33kV subsea cable to provide N-2 resilience to SSEN's sensitivity planning scenario (all distilleries decarbonise via electrification). Whilst SSEN's industry engagement indicates few distilleries currently have firm decarbonisation plans, the SWA aims to achieve net zero by 2045. The SWA further notes that whilst there are alternatives to electrification in order to decarbonise, they consider the electrification figures for Islay and Jura will be significantly higher than across Scotland due to the limited alternatives on the islands. We therefore consider SSEN's high demand scenario to have a high likelihood of materialising.

3.23 **Option 3A** meets the requirements of this scenario at lower cost than proceeding with **Option 7**, which can be augmented if the high demand scenario materialises. We note that **Option 3A** also provides industry with certainty and confidence in supply for electrification, something the SWA highlighted as a barrier to distillery decarbonisation plans. Overall, we acknowledge the inherent uncertainty in longer-term demand. However, in our view the longer-term benefits of installing a futureproofed solution outweigh the relatively low risk associated with over-delivery of capacity relative to **Option 7**.

3.24 While both **Option 3A** and **Option 2** would futureproof the network, **Option 3A** benefits from lower capital expenditure compared to SSEN's alternative 66kV option (**Option 2**), and offers enhanced resilience by enabling supply from two Grid Supply Points (GSPs). This suggests that **Option 3A** can deliver greater resilience at a reduced cost and therefore is considered as our preferred solution. However, we recognise that the proposed ED2 works under other 66kV options assessed and **Option 3A** are largely similar, apart from a switching station at Muasdale included in **Option 2**. The need to install a switching station has not yet been established and one could be installed later should the need arise. We have therefore decided to approve allowances for **Option 3A**, and will consider funding for a switching station in future should the need arise.

3.25 Our Final Determinations is to approve **Option 3A** with total project allowance of £34.116m during RIIO-ED2. We maintain our view to apply on-going efficiencies as it aligns with the RIIO-ED2 FDs. The approved solution has estimated Capex costs of £128.118m for ED3 and £0.876m for ED4. The ED3 and ED4 allowances do not include CAIs and risk, as SHET's submission did not include these.

Orkney

3.26 We have decided to provide funding for the first phase of SSEN's preferred solution, **Option 7A**, as this is the economic and efficient solution. The funding will enable the installation of a first 57km of 66kV subsea cable between Thurso South - South Ronaldsay via John Groats between 2024-2028, which may initially operate at 33kV. This mitigates the need to run Kirkwall Power Station under an N-1 outage scenario.

3.27 The additional analysis that SSEN provided on 132kV solutions suggest that these are significantly more expensive than 66kV solutions. We are satisfied that the analysis is robust and therefore that SSEN is correct in rejecting 132kV options.

3.28 SSEN's preferred option also includes upgrading PFW and PFE circuits to operate at 66kV between 2029-2032 while retaining the use of PFE3. However, the CBA does not support a view that this level of resilience is required. As such, we do not think that it is necessary to commit to the upgrade of PFW and PFE3 at this stage. We will consider additional funding requests for these upgrades should the need for them become clearer at the time of ED3 setting or during ED3. Please see further explanation in paragraphs 3.30 to 3.33 below.

3.29 We have reviewed the analysis that SSEN provided to support its preferred N-2 resilient option. In our assessment, the economic case for proactively providing full N-2 resilience is not compelling and we therefore do not think it would be appropriate to fund N-2 resilience. See further explanation in paragraphs 3.340 to 3.36 below).

Replacement of PFW and PFE3 cables

3.30 Based on their age and condition alone, it is unlikely that either PFW or PFE3 would need to be replaced before 2029-2033. Additionally, under a credible generation driven scenario, it remains the case that a second transmission link may be installed. In such a scenario, with two transmission links, PFW and PFE3 can be replaced with a single 66kV subsea cable and provide full N-2 resilience. Deferral of the decision on replacement of PFW and PFE3 would therefore allow for ongoing strategic network planning to enable Clean Power 2030 and Net Zero, to provide greater certainty on the need for a second transmission link, and therefore on whether it is better to replace the cable with two cables or a single 66kV cable.

3.31 Given the uncertainty around a second transmission link and the fact that the cables are not in immediate need of replacement, it would not be appropriate to provide funding for the proactive replacement of PFW and PFE3 at this point in time.

3.32 Our Final Determination is to approve SSEN's preferred solution, **Option 7A** for the first stage during RIIO ED2. However, for now our decision is to disallow the total costs associated with the second phase of its proposal, for the replacement of PFW and PFE3 cables. We welcome further engagement with SSEN on this topic as part of the RIIO-ED3 process.

3.33 We maintain our view to apply on-going efficiencies as it aligns with the RIIO-ED2 FDs and have adjusted allowances accordingly. These adjustments give the total project allowance of £17.010m within RIIO-ED2.

N-2 resilience

3.34 Regarding the request for further justification for proposed levels of resilience, SSEN maintains its proposal to provide N-2 resilience to mitigate against the loss of two subsea cables is needed. We recognise that the CBA analysis has been comprehensive and indicates that N-1 and N-2 solutions for Orkney have very similar NPVs and therefore, does not justify investment for N-2 resilience. This outcome is driven by the fact that the N-1 options retain the two existing 33kV subsea cables, the transmission link, and introduce one new 66kV subsea infeed. Consequently, even in a worst-case N-2 event involving the loss of the transmission link and the new 66kV circuit, PFW and PFE3 would maintain supply to Orkney. While there might be some customers that will experience outages under this scenario, the low value of lost load does not support additional investment for full N-2 resilience.

3.35 In response to our request for further exploration of the feasibility and cost-effectiveness of alternative options, such as relying on DEG in an N-2 scenario as an alternative to installation of a fourth subsea cable: SSEN provided sensitivity analysis where it considered the option of mitigating the delivery of an additional 33kV/66kV link to the islands by utilising a repowered embedded generation asset at Kirkwall and procuring flexibility to support the network. The analysis demonstrated that the two scenarios have practically identical NPVs with the option of utilising the Kirkwall station being slightly more favourable.

3.36 Similar to Islay-Jura, due to the Environmental Authorisations (Scotland) Amendment Regulations 2025, the existing DEGs will face operational restrictions as they cannot run on planned basis beyond 2033 and on unplanned basis beyond 2039. In addition to that, there is currently low offering of third-party flexibility opportunities and Kirkwall will not have sufficient capacity for use in the longer term as claimed by SSEN. Overall, we are satisfied that the preferred **Option 7A** mitigates the need to run DEG under an N-1 outage following the installation of the transmission link planned 2028, which is the level of security that SSEN are required to design the network[8].

Outer Hebrides and Skye

3.37 Following review of the further information provided by SSEN we agree that the intended scope of the HOWSUM mechanism is wider than we interpreted it to be

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[8] ENA_EREC_P2_Issue 8_(2023).pdf

in our DDs, and that the intent was for the mechanism to encompass a wider range of activities, including remote island generation where necessary. As stated in paragraph 3.2.105 of SpC3.2 that "*The Hebrides and Orkney Re-opener may be used where…the licensee has incurred costs associated with ensuring security of supply in the Scottish islands*".

3.38 Therefore, transmission outages affecting Lewis and Harris are beyond SSEN Distribution's control and stem from SSEN Transmission's accelerated infrastructure investments in the Outer Hebrides, which were not anticipated at the time of the ED2 business plan submission. In light of these circumstances, we consider HOWSUM to be the appropriate mechanism for recovering the associated costs.

3.39 SSEN provided a revised estimated cost of fuel and carbon for the four stations expected to operate during SSEN Transmission's notified outages which reflects the rescheduling of transmission outages, with significant activity now anticipated later in 2028/29.

3.40 Therefore, due to the revised outage programme, we have decided to approve the updated amount of £13.960m as additional funding for the planned outage periods in RIIO-ED2.

<u>Mull, Coll and Tiree</u>

3.41 SSEN confirmed that there are no changes to its January 2025 submission, and as such, we maintain our DDs position to approve additional development funding for SSEN of £1.160m.

Cost assessment

<u>Development costs: Islay-Jura; Orkney; Outer Hebrides and Skye; Mull, Coll and Tiree</u>

3.42 We maintain our decision to approve the additional development funding without amendment. This funding is linked directly to the solutions for Islay-Jura, Orkney, Outer Hebrides and Skye, Mull, Coll and Tiree, and therefore, in order to avoid double funding, will be netted off any future allowances relating to these island solutions.

<u>Indirect costs (CAIs)</u>

3.43 We revisited our assessment of the indirect costs, and after additional discussions on this topic and further explanation provided by SSEN we consider that development funding (such as the £20.6m HOWSUM Development Funding allowance included in SSEN's ED2 allowances) and delivery costs are clearly distinguishable. Costs for construction, commissioning, or asset integration activities fall under the CAI costs according to the RIGs. The two funding streams are for different stages of the project lifecycle as the development fund is related to planning and optioneering phase while the CAI costs are related to execution phase.

3.44 We have now decided to approve the requested funding for the indirect costs for both 2024 and 2025 HOWSUM submissions. This approval is based on SSEN's application of the 10.8% scaling factor on the approved allowances for each project within HOWSUM ensuring consistency and proportionality in the treatment of these costs. We acknowledge that the 10.8% indirect cost allowance applied to LRE programmes represents a reasonable and consistent benchmark, and we agree its application to HOWSUM is appropriate.

3.45 We have decided to approve CAI costs of £4.835m for 2025 and of £8.189m for 2024; total funding allowance for CAI costs is £13.024m.

<u>Risk allocation</u>

3.46 SSEN's request was for £24.000m risk allowance, which it split between £11.440m in standard risk costs and £12.560m in extraordinary risk costs. For projects where risks are well-understood and SSEN has relevant delivery experience, standard allowances have been defined and requested. Typically, these cover risks such as delays due to consenting and access, weather-related issues during subsea cable work, and ground condition uncertainties. SSEN quantified these risks using a deterministic approach, assigning maximum likely costs to each identified risk to form an overall risk value.

3.47 Certain cost risks which were identified by SSEN to be outside of its control or its supply chain (i.e. market volatility), were included in their January 2025 application as extraordinary risk allowances. They were estimated at 15% of delivery costs and applied across all island projects. According to SSEN, this approach reflects the lack of an appropriate cost adjustment mechanism and the exposure faced by SSEN, particularly around the submarine cable activities.

3.48 In our DDs, our assessment focused on identifying the most appropriate solutions for each of the Scottish Islands' projects. Given that the proposed risk allowances were intrinsically linked to delivery costs, and considering our position on the underlying project justification, we considered it unnecessary to expand our assessment on those costs at that stage.

3.49 We are satisfied with SSEN's assessments of standard risks as they are informed by SSEN's experience in delivering submarine cable and onshore projects in comparable locations. However, SSEN has not provided sufficient evidence to demonstrate that the likelihood associated with the risks it has classified as extraordinary risk are sufficiently high to justify the award of specific allowances to cover them.

3.50 Our Final Determinations is therefore to approve allowances of £5.587m related to standard risks, but to disallow the requested extraordinary risk costs.

3.51 For the remaining island projects, we have not approved funding for risk allowances at this stage, as these projects are not planned for delivery within RIIO-ED2.

3.52 In summary, our FDs on the allowance for 2025 HOWSUM re-opener are summarised in the below table.

Table ED7: Summary of Hebrides and Orkney Re-opener Projects Allowances (£m 2020/21 prices)

Project/ Activity	Cost category	SSEN Total Project Forecast (£m)	SSEN's Total Cost Forecast for ED2 (£m)	ED2 Allowances (£m)	ED3 Allowances (£m)	ED4 Allowances (£m)	Total Project Allowances (£m)
Islay-Jura	Capex	157.535******	75.570	28.541	+128.118	+0.876	157.535
Islay-Jura	Risk and CAI costs	28.440*	28.440*	5.575**	+10.087*****	+0.069*****	15.732
Orkney	Capex	172.638******	8.140	8.140	-	-	8.140
Orkney	Risk and CAI costs	8.900*	8.900*	7.307**	-	-	7.307
Outer Hebrides and Skye	Capex	-	-	-	-	-	-
Outer Hebrides and Skye	Risk and CAI costs	24.620*	24.620*	17.010***	-	-	17.010
Mull, Coll and Tiree	Capex	-	-	-	-	-	-
Mull, Coll and Tiree	Risk and CAI costs	2.070*	2.070*	1.160****	-	-	1.160
Whole system analysis	Capex	-	-	-	-	-	-
Whole system analysis	Risk and CAI costs	1.360*	1.360*	1.230****	-	-	1.230
CAI costs – 2024 HOWSUM	CAI	9.490	9.490	8.189	-	-	8.189
Total	-	**405.053**	**158.590**	**77.153**	**+138.205**	**+0.945**	**216.303**

** SSEN's other cost elements include standard, extraordinary risk allowances, CAI costs and development fund requested where appropriate for RIIO-ED2.*

*** ED2's other cost elements include standard risk allowances and CAI costs for Islay-Jura, standard risk allowances, CAI costs and development fund for Orkney.*

**** ED2's other cost elements for Outer Hebrides and Skye include development fund and DEG costs*.

***** ED2's other cost elements for Mull, Coll and Tiree and Whole system analysis include development fund only.*

****** ED3 and ED4's other cost elements include the risk allowances estimated at the same ratio as ED2, the other cost elements will be determined in subsequent price control periods.*

******* SSEN Total Project Forecast values include the capex cost for SSEN's preferred solution for Islay-Jura and Orkney during the RIIO-ED2, RIIO-ED3 and RIIO-ED4 where appropriate.*

4. Next Steps

4.1 We have considered all consultation responses and concluded our assessment of the 2025 Hebrides and Orkney re-opener and the Load Related Expenditure re-opener.

4.2 To give effect to our Final Determinations on the Hebrides and Orkney re-opener, we will publish shortly a direction to modify the HOt term in Appendix 1 of SpC 3.2 of SSEH's electricity distribution licence. These modifications come into effect immediately.

4.3 We will also publish shortly a consultation our proposed modifications to ENWL's electricity distribution licences that give effect to our FDs. The consultation will also include proposals to modify ENWL's and SSEN's licences to enable us to set Price Control Deliverables (PCDs) relating to the allowances we have determined under the Load Related Expenditure Re-opener and Hebrides and Orkney Re-opener mechanisms.

Appendices

Appendix 1 SpC 3.2.105 - List of Activities under Hebrides and Orkney Re-opener

3.2.105 The Hebrides and Orkney Re-opener may be used where:

a) the licensee has incurred or expects to incur costs as a result of changes to the scope or timing of work relating to twelve sub-sea cables:

   i. Skye to Uist (North route);

   ii. Skye to Uist (South route);

   iii. Pentland Firth West;

   iv. Pentland Firth East;

   v. Mainland Orkney – Hoy South;

   vi. Orkney (additional 66kV circuit)

   vii. Eriskay – Barra 2;

   viii. South Uist – Eriskay;

   ix. Mull to Coll (double circuit);

   x. Coll - Tiree (double circuit);

   xi. Mainland - Jura (double circuit); and

   xii. Jura - Islay (double circuit); or

b) the licensee has incurred costs associated with ensuring security of supply in the Scottish islands, and can demonstrate efficient whole systems considerations have been taken into account, including considering alternative activities to installing the cables listed in paragraph (a); or

c) the licensee has incurred or expects to incur costs associated with the outcomes of additional whole system analysis in the Scottish Islands to contribute to Net Zero Carbon Targets and ensure long-term security of supply, including any alternative activities to installing the cables outlined in (a); and

d) the change in those costs in paragraphs (a) or (b) exceeds the Materiality Threshold and are not otherwise funded by the SpCs.

Appendix 2 SpC 3.2.75 - List of Activities under LRE Re-opener

3.2.75 The LRE Re-opener may be used where:

(a) the licensee's LRE has increased or is expected to increase, as a result of an increase in:

i. current or forecast load-related constraints on the Distribution System that are in place at the time the licensee makes a LRE Re-opener application relative to the constraints associated with the forecast demand used by the Authority to set ex ante allowances for the Price Control Period; or

ii. the proportion of expenditure associated with load-related constraints on the Distribution System to be funded through Use of System Charges relative to the assumptions used by the Authority to set allowances that are in place at the time the licensee makes a LRE Re-opener application; or

(b) there is a change in conditions on the Distribution System relative to the assumptions used to set allowances; and

(c) the increase or expected increase in LRE:

i. is not provided for by the sum of LRE ex ante non variant allowances specified in Appendix 2 of the Licence, and any previously directed values for LRE_t and $SINV_t$;

ii. is not provided by the operation of SpC 3.9 (Load Related Expenditure Volume Drivers); and

iii. exceeds the Materiality Threshold.

Appendix 3 Shortlist of options considered for Islay-Jura evaluation of a three subsea cable solution

Option No.	Option Description	Demand Case
Option 1	Install auto-close scheme at Port Ellen 33kV substation, install 3 x 66kV circuits from Crossaig to Port Ellen, reinforce Bowmore - Port Ellen (1&2) circuits	Low Confidence (Sensitivity)
Option 2	Install auto-close scheme at Port Ellen 33kV substation, install 3 x 66kV circuits from Carradale to Port Ellen, reinforce Bowmore - Port Ellen (1&2) circuits	Low Confidence (Sensitivity)
Option 3A	Install auto-close scheme at Port Ellen 33kV substation, install 2 x 66kV circuits from Carradale to Port Ellen, 1 x 66kV from Port Ann - Knocklearach, reinforce Bowmore – Knocklearach (1&2) and Bowmore - Port Ellen (1&2) circuits	Low Confidence (Sensitivity)
Option 3B	Install auto-close scheme at Port Ellen 33kV substation, install 2 x 66kV circuits from Carradale to Port Ellen (single circuit from Carradale to Muasdale switching station and single circuit from Kilnaughton Bay to Port Ellen), 1 x 66kV from Port Ann - Knocklearach, reinforce Bowmore – Knocklearach (1&2) and Bowmore - Port Ellen (1&2) circuits	Low Confidence (Sensitivity)
Option 4	Install auto-close scheme at Port Ellen 33kV substation, install 2 x 66kV circuits from Carradale to Port Ellen, 1 x 66kV from Port Ann - Knocklearach, reinforce Bowmore – Knocklearach (1&2) and Bowmore - Port Ellen (1&2) circuits. Install 66kV assets in RIIO ED2 but run at 33kV until 2040 when the additional LOW CONFIDENCE demand materialises	Low Confidence (Sensitivity)
Option 5	Low Confidence (Sensitivity) January EJP Option: Install auto-close scheme at Port Ellen 33kV substation, install one 33kV circuit from BAT Wind Farm I (Carradale GSP) to Port Ellen, one 33kV circuit from BAT Wind Farm III (Carradale GSP) to Port Ellen , install Port Ann - Knocklearach circuit, one 33kV circuit from Carradale new 33kV busbar - Port Ellen, install 2nd Jura - Islay circuit, upgrade Lochgilphead - Knocklearach, Bowmore - Knocklearach circuit and Bowmore - Port Ellen (x2)	Low Confidence (Sensitivity)

Option 6	Install auto-close scheme at Port Ellen 33kV substation, install 2 x 33kV circuits from Carradale to Port Ellen (single 45MVA 33kV circuit between Carradale to Muasdale switching station onshore section), 1 x 33kV from Port Ann - Knocklearach, reinforce Bowmore - Knocklearach, reinforce Lochgilphead - Knocklearach and install 2nd Jura - Islay cable	Low Confidence (Central)
Option 7	**Original January EJP Option** : Install 3 new 33kV circuits to Islay (one from BAT Wind I and one from BAT Wind III and one from Port Ann GSP), and install a second Islay – Jura submarine cable to augment the existing Islay-Jura circuit	Low Confidence (Central)

Appendix 4 Shortlist of options considered for Orkney

Option	Option Description
Option 1	Install 57km 132kV Thurso South - South Ronaldsay via John Groats by 2033 Upgrade PFW circuit to be running at 66kV between 2029-2032 Install Pentland - Hoy 66kV circuit between 2033 and 2040 Keep 33kV PFE 3 circuit
Option 2	Install 57km 132kV Thurso South - South Ronaldsay via John Groats by 2033 Upgrade PFW circuit to be running at 132kV by 2033 Reinforce 33kV Kirkwall - South Ronaldsay network (three 33kV circuits) Keep 33kV PFE 3 circuit
Option 2B (Sensitivity Check Utilising DEG & Flex)	Install 57km 132kV Thurso South - South Ronaldsay via John Groats by 2033 Upgrade PFW circuit to be running at 132kV by the end of ED4 and use KPS plus flex to support the network before the completion of 132kV PFW upgradation Reinforce 33kV Kirkwall - South Ronaldsay network Keep 33kV PFE 3 circui
Option 3	Upgrade PFW and PFE circuit to be running at 132kV by 2033
Option 4	Install 57km 132kV Thurso South - South Ronaldsay via John Groats by 2033 Install the second 132kV Finstown Link by the end of ED4 Reinforce 33kV Kirkwall - South Ronaldsay network Keep 33kV PFE 3 circuit

Option 7A (Hybrid Option Preferred Jan 25 Submission)	Install 57km 66kV Thurso South - South Ronaldsay via John Groats between 2024-2028 (running at 33kV). Upgrade PFW and PFE circuits to be running at 66kV between 2029-2032 and retain the use of PFE3