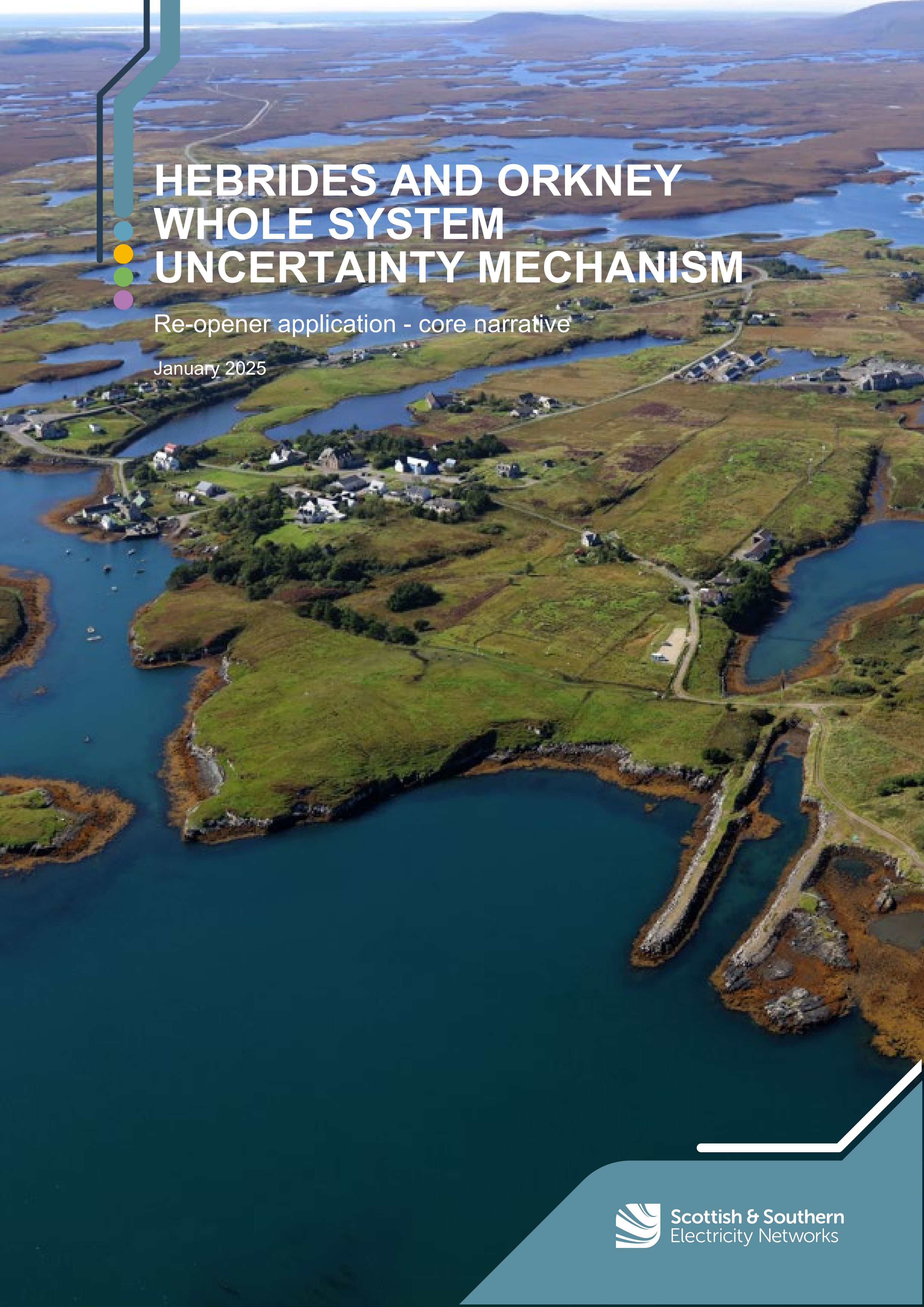

HEBRIDES AND ORKNEY WHOLE SYSTEM UNCERTAINTY MECHANISM

Re-opener application - core narrative

January 2025

Scottish & Southern Electricity Networks

CONTENTS

ABOUT SSEN DISTRIBUTION

Who we are

SSEN Distribution (SSEN) is responsible for the operation and maintenance of the electricity distribution networks north and west of the central belt of Scotland and across central southern England.

Through our two licensed electricity distribution network areas, Scottish Hydro Electric Power Distribution (SHEPD) and Southern Electric Power Distribution (SEPD), we deliver power to over 3.9m homes and businesses, with over 111,000 substations and pole-mounted transformers and 128,000km of overhead lines and underground cables across one third of the UK land mass.

We serve some of the most diverse and unique geographies across the UK, and keep customers and communities connected whilst developing the flexible electricity network vital to achieving net zero. Our network serves some of the UK's most remote communities and some of the most densely populated. Our two networks cover the greatest land mass of any of the UK's Distribution Network Operators (DNOs), covering 72 local authority areas and 75,500km2 of extremely diverse terrain.

Our core purpose is to power communities to thrive today and create a net zero tomorrow. We have a responsibility to supply customers with safe and reliable power, allowing them to focus on the things that matter most, while we work hard to build a smarter, flexible, greener network that's fit for the future.

SSEN is part of SSE, a UK-listed company that operates across the energy sector and its activities and investments contribute around £9bn to the UK economy every year.

Scottish Hydro Electric Power Distribution (SHEPD)

The electricity distribution network in the north of Scotland covers a quarter of the UK landmass, powering nearly 800,000 homes and businesses across 15 local authority areas and serves island communities across 60 inhabited islands with over 110 dedicated submarine cable installations. The licence area stretches northwards from Loch Lomond and Dundee up to Orkney and the Shetland Islands. It is a unique region, containing the farthest western and northern mainland points in Great Britain.

As our communities strive to meet their net zero ambitions, we're preparing our network to accommodate the uptake of low carbon technologies across the region and significant increase in local generation connections.

EXECUTIVE SUMMARY

Introduction

The SHEPD network faces unique challenges as it transitions to net zero, and our investment in the north of Scotland during RIIO-ED2 will be the foundation for our net zero future. We serve the needs of our customers located across 60 inhabited Scottish islands via an extensive submarine cable network with Distributed Embedded Generation (DEG) stations providing strategic back up, which are unique responsibilities among electricity licensees. **Our island networks connect some of our most remote communities and provide export routes for large amounts of renewable generation, critical to meeting national and UK net zero targets.**

The need to consider the future requirements of these communities formed an important component of our RIIO-ED2 Business Plan and was recognised by Ofgem through the introduction of dedicated mechanisms including the Hebrides and Orkney Whole System Uncertainty Mechanism (HOWSUM) re-opener, under which we make this application, designed to deal with the region's set of unique circumstances. Underpinning the HOWSUM was recognition of the need to take whole system approaches in designing and delivering solutions for the Scottish islands.

Approach to assessing needs on the Scottish islands

Our January and July 2024 applications focused on the future needs of the Outer Hebrides (Skye – South Uist, Uist – Eriskay, Eriskay - Barra), and the completed Pentland Firth East 3 project. **This application focuses primarily on the future requirements of the Inner Hebrides and Orkney islands and provides updates on our strategic plan for the Outer Hebrides and Skye, and the Shetland islands.** We have applied our assessment across the following discrete island groups:

1. The Outer Hebrides;
2. The Inner Hebridean islands of Mull, Coll and Tiree;
3. The Inner Hebridean islands of Jura and Islay; and
4. The Orkney islands.

We have worked with stakeholders to identify pathways for these communities to achieve net zero efficiently and securely. This is in line with our national approach to strategic investment delivered through our strategic development planning process. This approach allows for a common methodology to be applied consistently across geographic areas, whilst also providing latitude to consider specific locational issues and complexities. The strategic planning process as applied to HOWSUM is shown below in Figure 1.

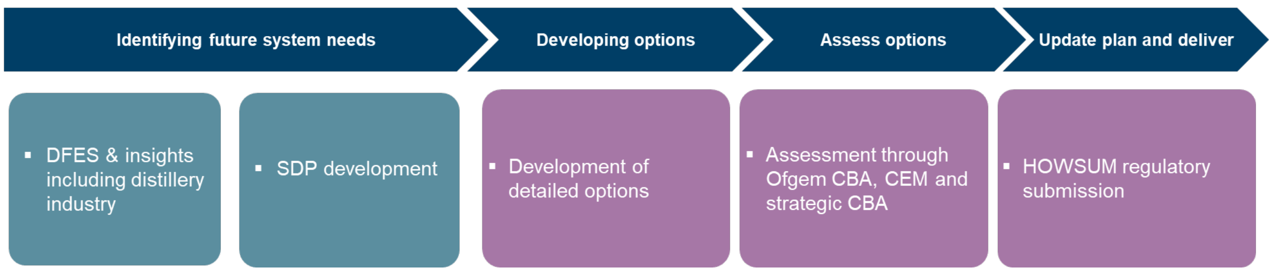

Figure 1: Strategic Development Planning process as applied to HOWSUM

We have assessed future system needs through to 2050 for each island group, using whole system analysis to understand future energy needs and ensure our proposals consider factors such as transmission developments, the use of flexibility and emerging technologies. We are developing and consulting on Strategic Development Plans (SDPs) for these areas. A similar approach is required for the Shetland islands, which will be progressed within RIIO-ED2 for inclusion in our RIIO-ED3 recommendations, consistent with the other island groups.

The key drivers across the islands are **demand and generation growth, network resilience, and decarbonisation of both our customer base and our diesel power stations**. We have built on the work that fed into the January and July 2024 HOWSUM applications to consider the future needs of the island communities in more detail, initially through work with Regen, and adding deeper analysis of the decarbonisation requirements of industry important on the islands. An overarching theme has emerged: **the need to reduce emissions and decarbonise operations on the Scottish islands**. Stakeholders have told us about their **decarbonisation plans** to connect local and community renewables generation, and about the importance of this transition to homes, businesses and industry. We have worked with organisations such as the Scotch Whisky Association to better quantify this requirement and launched our SeaChange innovation project to understand the impacts of maritime decarbonisation. **Decarbonisation of demand has the potential to radically affect our Scottish islands network.** We believe our strategic planning process, and the 2050 plans contained within this application, will ensure we are building the distribution capacity that our customers need to achieve net zero.

Our approach to strategic planning mitigates the inherent uncertainties associated with long-term projections of demand and generation requirements. We progress least-regrets interventions with immediate drivers for change, whilst continuing to review and refine longer-term needs. This allows us to **proactively develop our network ahead of need while ensuring we make efficient decisions for the consumer through minimising the risk of early sub-optimal investment**. Our methodology also assesses **non-network options**, including the use of third party flexibility services where possible, which is important to stakeholders and can offer efficient alternatives to network investment. We have substantiated our analysis of the opportunity for flexibility by testing the market through a recent Request For Information process (RFI), which confirmed interest but outstanding challenges for this these arrangements.

Our 2050 plans and the work we will deliver in RIIO-ED3 will remove our reliance on DEG by 2033 subject to regulatory funding. Decarbonising DEG is critical to ensure we meet our Science Based Targets on the pathway to net zero, and the ambition of the Scottish Government to reduce industrial emissions. We aim to achieve this through a combination of additional network investment, complemented by replacing DEG with zero carbon alternatives, including third-party solutions where efficient and deliverable. Our work on the future of Tiree Power Station and our exploration of flexibility services in the Outer Hebrides are the start of this focus and we will use development funding strategically to continue this work through RIIO-ED2.

Overview of 2050 strategic plans for each island group

Inner Hebridean Islands of Islay and Jura

These islands are currently supplied by a single circuit from Port Ann GSP including submarine cables between the mainland and Jura, and between Jura and Islay. Network resilience is met by Bowmore Power Station.

This archipelago is a centre for the global whisky industry which is keen to decarbonise but currently relies on carbon sources for heating. Decarbonisation of the whisky industry along with other forecast demand increases, including maritime decarbonisation, is projected to drive significantly higher network capacity requirements for these islands. We therefore need to invest to increase the capacity of our network to these islands, whilst also removing the need to operate Bowmore Power Station.

The current optimum 2050 plan is shown below in Figure 2. The proposed additional works to connect the islands (dotted green lines) consist of four new 33kV cables to be delivered between RIIO-ED2 and

RIIO-ED3. This 33kV approach allows incremental capacity increases to be made as the whisky industry decarbonises, whilst delivering an efficient solution.

Within RIIO-ED2 we will connect Islay to Carradale GSP through two new 33kV cables to Port Ellen on Islay, which initial analysis suggests is the quickest method to deliver increased capacity and, by installing two cables together, should achieve cost efficiencies. Connection to Carradale GSP also enhances the resilience of supplies to this island group. We will utilise our existing HOWSUM development funding baseline allowance for development activities, and in addition to project capital expenditure (capex) we will require funding for risk and CAIs.

During RIIO-ED3 we plan to provide additional capacity and resilience from Port Ann to Islay and Jura. This will consist of new 33kV circuits from Port Ann – Knocklearach on Islay and a second cable from Islay – Jura. Our analysis indicates that this infrastructure will allow industrial decarbonisation, facilitate future demand forecasts, and remove reliance on Bowmore Power Station by 2033. To further manage the interconnectivity across the islands we will be installing a 33kV auto-close scheme at Port Ellen. Looking beyond RIIO-ED3 we will need to complete upgrades to the existing Lochgilphead – Knocklearach and Bowmore – Knocklearach 33kV overhead lines by 2040. Figure 2 shows both the existing 33kV and 11kV networks in solid green and red lines respectively. The proposed additional works to connect the islands are shown as dotted green lines and consist of four new 33kV cables with spend forecast across both RIIO-ED2 and RIIO-ED3. Figure 2 shows our 2050 strategic plan for Islay and Jura. Figure 3 shows the indicative timeline for our 2050 proposals.

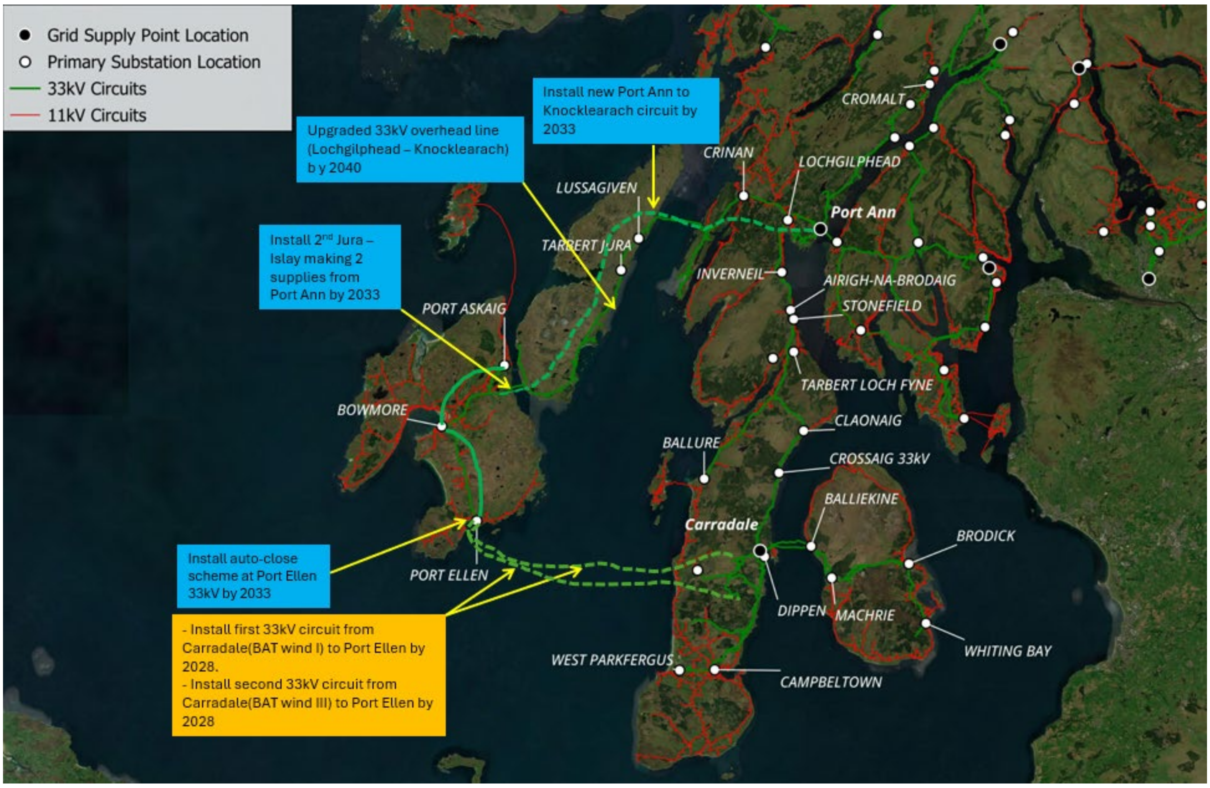

Figure 2: 2050 strategic plan for Islay and Jura

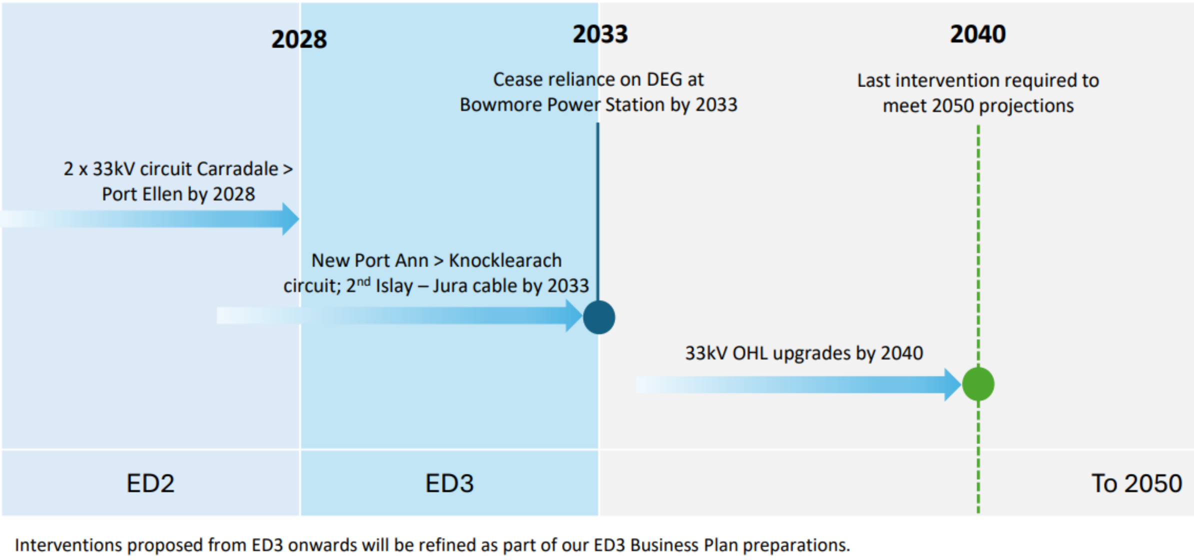

Figure 3: 2050 timeline for Islay and Jura

Orkney islands

The existing Orkney network is fed via two 33kV circuits from the GB mainland, including four submarine cable sections. It is an area of significant activity of renewables generation connections and a new 220kV AC circuit from mainland Scotland to a new GSP at Finstown is in development.

We have worked with SSEN Transmission to ensure our 2050 plans align with their programmed works and potential future developments. This includes consideration of further transmission connections and consequential infrastructure development such as a second transmission link from Finstown, and the use of potential OFTO infrastructure needed for offshore based projects connecting directly into the mainland network.

As these proposals are not certain, particularly in light of recent national policy updates such as Clean Power 2030, we have considered two potential pathways for future change.

1. Demand Resilience Pathway: Under this pathway future requirements would be driven by increased electrical demand on the Orkney islands. In this case a second Orkney transmission link would not be required, but additional capacity would need to be created through replacement of existing 33kV infrastructure with 66kV equipment. Works in RIIO-ED2 would be limited to the installation of a new 66kV circuit between Thurso – St Margaret's Hope via John O'Groats. The strategic plan for this pathway is shown in Figure 4.

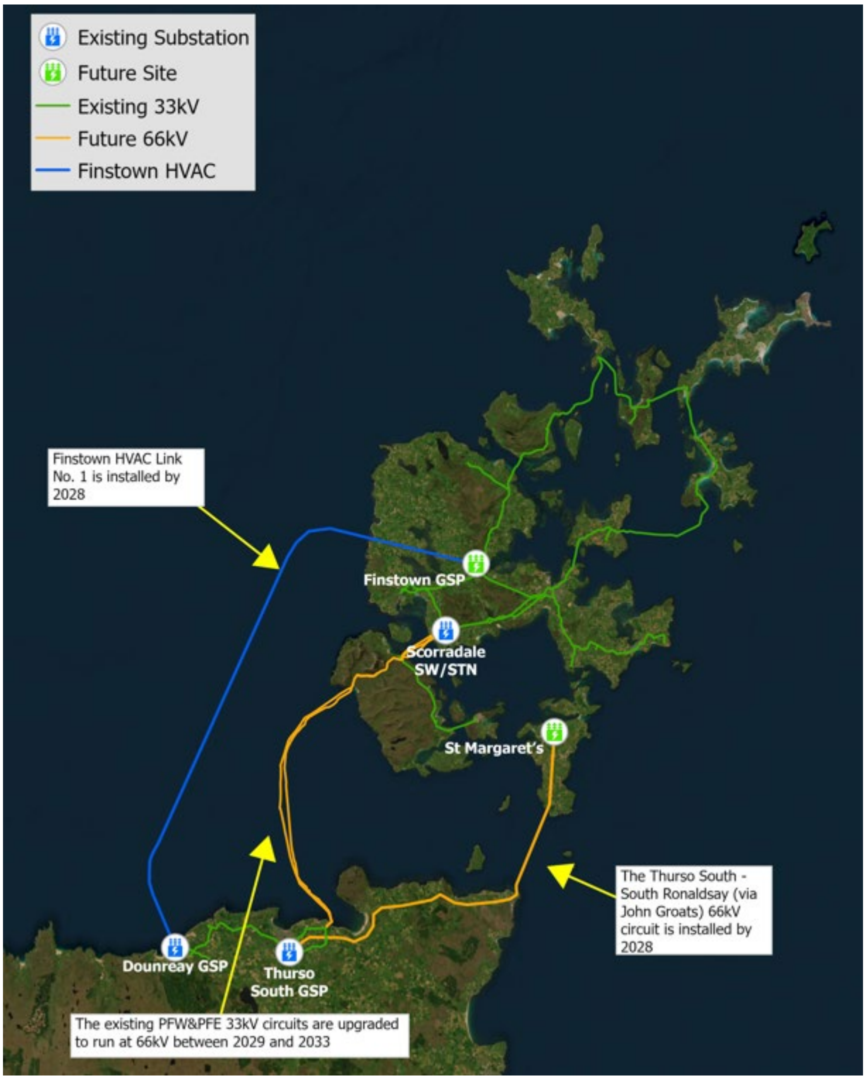

Figure 4: 2050 strategic plan for Orkney – Demand Resilience Pathway (Option 7)

2. Generation Export Pathway: Under this pathway there would be a significant volume of renewable generation seeking connection to the network on Orkney, driving the need for a second transmission link to the mainland. Such a link could also provide benefits for the local distribution network including additional import capacity and resilience. This scenario would require incremental change to the existing 33kV network through the implementation of three additional 33kV circuits, the first of which would be required during RIIO-ED2 from Thurso to St Margaret's Hope, via John O'Groats. Kirkwall Power Station would also need to be replaced by flexibility services for a defined period in the 2030s. This 2050 strategic plan is shown in Figure 5.

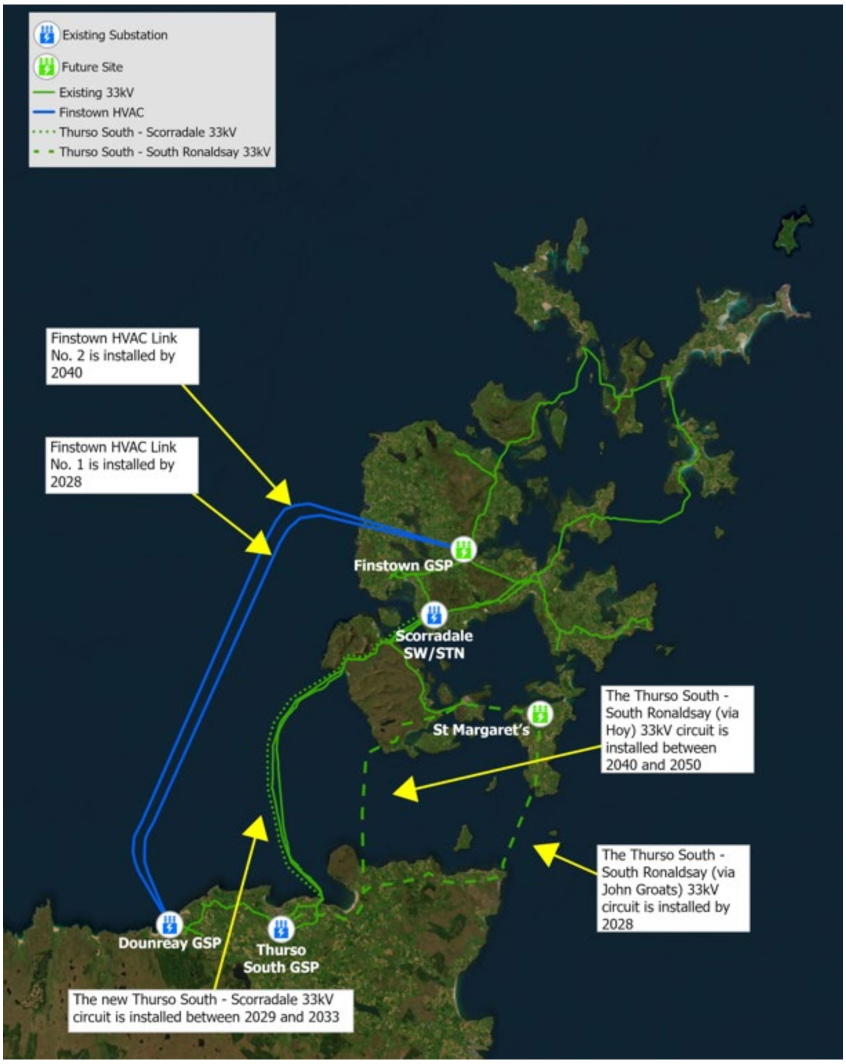

Figure 5: 2050 strategic plan for Orkney – Generation Export Pathway (Option 2)

Our analysis shows that a common optimum way forward in RIIO-ED2, which maintains the optionality of these pathways, is the installation of the new circuit between Thurso South and St Margaret's Hope via John O'Groats, shown at Figure 6. We intend to construct this circuit at 66kV but initially operate it at 33kV, introducing 66kV into the SHEPD asset base for the first time. We will utilise our remaining HOWSUM development funding baseline allowance on this project but will require further development funding to cover all of the early stage works. In addition to project capex, we will require funding for risk and CAIs associated with the project. We will continue engagement with SSEN Transmission and other stakeholders to optimise the future pathways ahead of RIIO-ED3. Figure 7 shows the indicative timeline for our 2050 proposals.

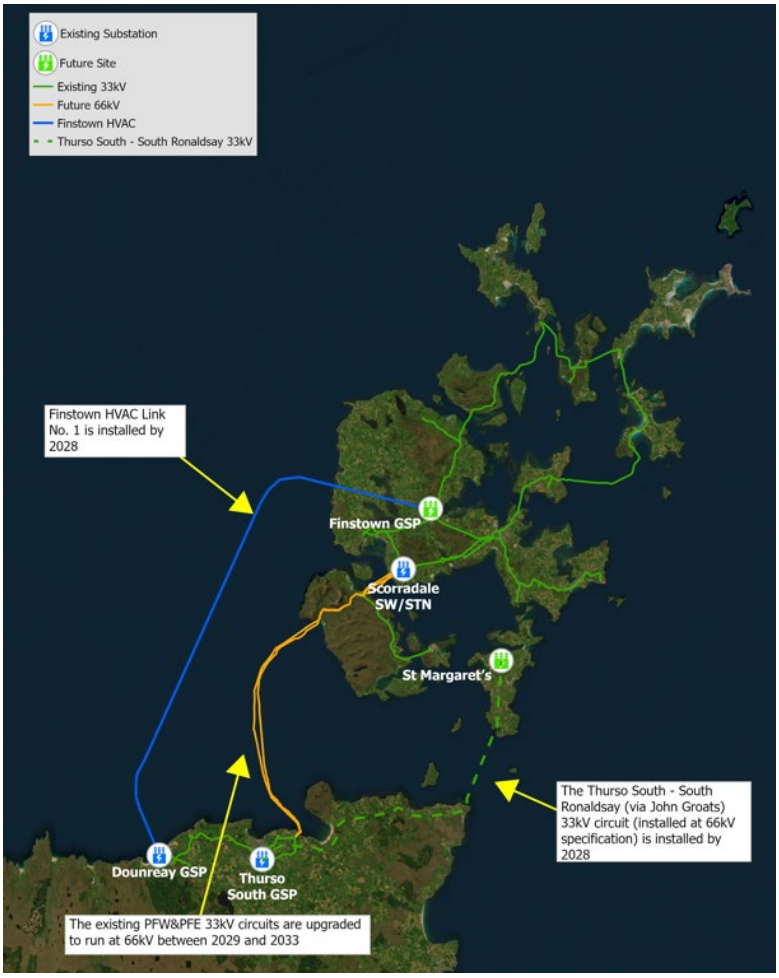

Figure 6: 2050 strategic plan for Orkney - Hybrid Solution (Option 7A)

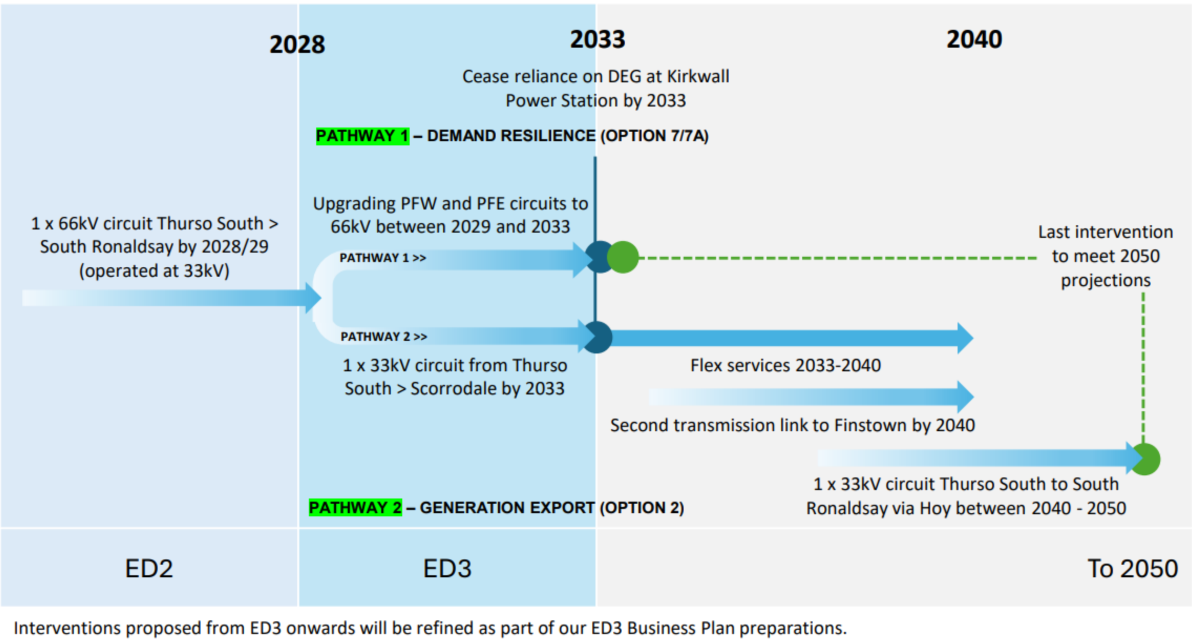

Figure 7: 2050 timeline for Orkney

Inner Hebridean Islands of Mull, Coll and Tiree

These islands are currently supplied via two 33kV circuits fed from Taynuilt GSP, which includes four submarine cables between the Scottish mainland, Kerrera and Mull. There is a third circuit available in this area, however it has been designed to back-feed the Morvern peninsula in the event of an outage on the Fort William network, and therefore has limited capacity. Tiree and Coll are supplied by a single 11kV feeder from Mull with resilience provided via Tiree Power Station.

Our strategic plan for this island group has considered two discrete elements:

- Works required for Mull, Coll and Tiree
- Works required for Coll and Tiree only

We consider each of these options below.

Mull, Coll and Tiree

Currently there are no identified interventions required for this island group in RIIO-ED2, but a third circuit is required between Mull and mainland Scotland during RIIO-ED3 to meet future resilience and demand requirements. The optimum solution is a new 33kV circuit from Tullich switching station on the mainland to Lochdonhead primary substation on Mull. This indicative solution is shown in Figure 8.

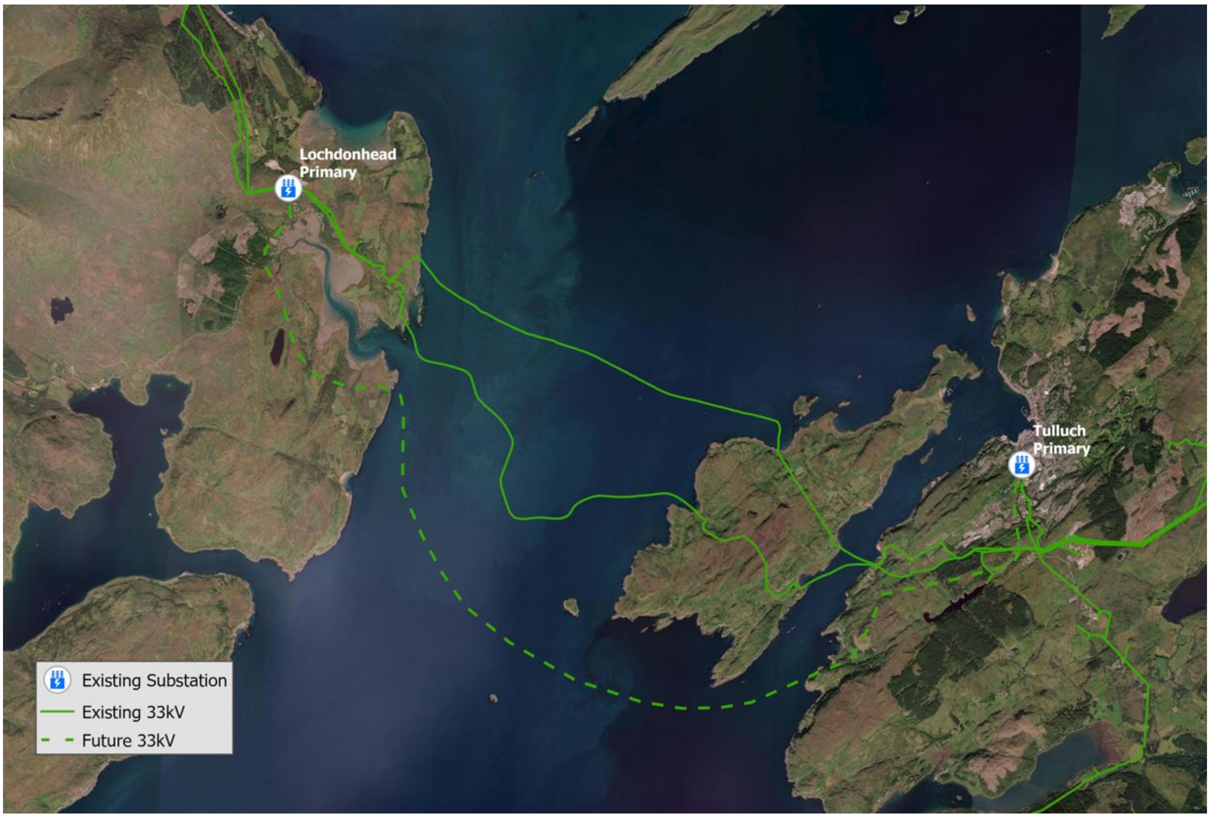

Figure 8: Indicative 2050 strategic plan for mainland Scotland to Mull

Coll and Tiree developments

The primary driver for these islands is future network resilience. We have considered a range of options including replacement of Tiree Power Station, potentially with a third-party solution. We have also considered, utilising our DFES projections, whether additional network capacity could facilitate local generation to connect to these islands. To support us in these considerations, we have used our Strategic CBA to understand the potential benefits of increased generation and reduced DEG emissions. This has shown an optimum solution would be the addition of a second 11kV cable from

Mull to Coll, potentially replacing Tiree Power Station with a third-party solution providing peak management services [redacted], as shown in Figure 9.

These works would not be required until RIIO-ED3 and we will continue to develop these proposals through RIIO-ED2. We will explore in more detail the costs and technologies available for replacement of Tiree Power Station, including the viability of third-party alternative solutions. Given the phasing of the activities, within RIIO-ED2 we expect to require only development funding, and associated risk and CAI allowances, for this island group.

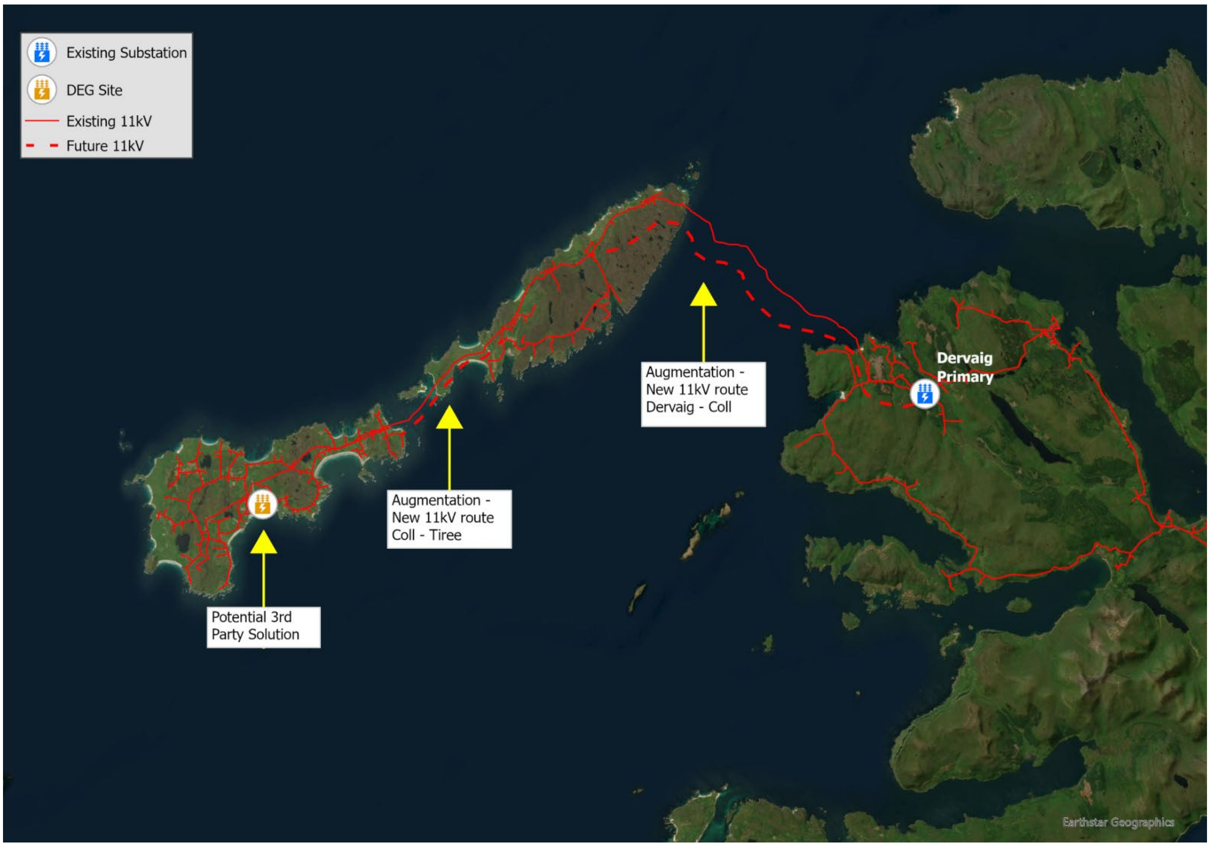

Figure 9: Indicative 2050 strategic plan for Mull, Coll and Tiree

Outer Hebrides and Skye

The Outer Hebrides are fed by a transmission network running from Fort Augustus through Skye to Ardmore, which connects to Lewis and Harris via a 33kV submarine cable link. The Uist archipelago is fed from Ardmore GSP on Skye via a 33kV submarine cable to Loch Carnan. Figure 10 shows these cables and the location of the main power stations used to provide back-up supplies in the event of loss of supply from the in-feeding network (Battery Point, Arnish, Loch Carnan and Barra power stations).

We provided significant detail on our strategic plan for the Outer Hebrides in our January 2024 and July 2024 HOWSUM applications. The plan consists of the replacement of the existing Ardmore – Uist cable with a higher rated circuit from Dunvegan GSP to Loch Carnan on South Uist, supplemented with the addition of a 'delivery optimisation loop' between Ardmore GSP and Loch Pooltiel. This addition is to ensure timely delivery of a replacement circuit to the Uists, to manage failure risk of the existing Ardmore – Loch Carnan cable. Future interventions include a second 33kV circuit between Ardmore and Harris GSPs, and a new 33kV circuit between Clachan switching station and Harris GSP. These works are required in longer timescales with forecast delivery in RIIO-ED3. The plan is summarised in Figure 10.

Figure 10: 2050 strategic plan for Outer Hebrides and Skye

We are reviewing this plan as part of our broader work to consider the strategic needs of the Outer Hebrides and Skye networks. We will be publishing our SDP for this network area in early 2025 but do not expect a significant change to the current 2050 strategic plan. This will include how the planned optimisation loop can form an integral part of the future plans for both Skye and the Outer Hebrides.

We have continued to work with SSEN Transmission to understand the operational needs of this area of the network both in RIIO-ED2 and longer-term following commissioning of the planned High Voltage Direct Current (HVDC) link. There are significant planned 132kV outages required on the Outer Hebrides and Skye during RIIO-ED2 to facilitate transmission works including the rebuilding and augmentation of the existing 132kV route on Skye. This will require us to run DEG plant more frequently than we planned for in our RIIO-ED2 Business Plan submission. While have worked with SSEN Transmission to look to minimise this requirement and are working to secure flexibility services which may further reduce the use of DEG, we have requested an additional [redacted] of DEG operational costs to maintain supplies to this region during SSEN Transmission's planned operations. In addition, we are seeking further development funding to enable us to progress works in our strategic 2050 plan ahead of RIIO-ED3, and an associated small element of risk and CAI funding.

Shetland

As a truly islanded network the Shetland distribution system is currently supplied via the DEG at Lerwick Power Station, and Sullom Voe Terminal. Power is distributed to the eleven primary substations via the 33kV distribution network. However, Shetland is in the process of being connected to the GB network through the Shetland HVDC Link and a new GSP at Gremista. These works, and the associated distribution requirements, are discussed further in the Shetland uncertainty mechanism submission.[1]

1 Shetland Energy - SSEN

We are building on this work to understand the future needs of this island group to 2050. The published draft SDP for Shetland[2] contains an initial high level strategic plan of future network requirements and will be confirmed in the final published plan. This will be informed by stakeholder feedback and will be progressed further through detailed optioneering in a similar manner to the HOWSUM proposals.

Our plan for delivery and further development activity in RIIO-ED2

We will continue to refine the strategic plans for all Scottish island groups to form a critical component of our RIIO-ED3 Business Plan submission. This will continue to review stakeholder insights and developments from future islands-focused engagement as well as onboarding learnings from the RIIO-ED2 HOWSUM programme to refine our approach.

Our work will include **further development activities** required to progress projects identified for delivery in RIIO-ED2, those being delivered between RIIO-ED2 and RIIO-ED3, and projects identified for delivery in RIIO-ED3. Island stakeholders have repeatedly told us of the urgency of this work and the need for momentum. A continuation of the development fund will help to bridge an identified gap in funding of ongoing RIIO-ED2 works and works between RIIO-ED2 and RIIO-ED3. Our Skye – South Uist project is a good example of the development fund allowing continued whole system solution development work while regulatory determinations are in process.

Our HOWSUM development funding baseline allowance covers only part of the costs of development works identified and required to be undertaken in the remainder of RIIO-ED2. As such our request for additional development funding ensures all of these activities are funded, and will help to prevent delays in delivery where this is within our control.

We emphasised the impacts of **volatile market conditions** in our July 2024 Addendum, resulting in **more risk and cost uncertainty in procurement and delivery**. In addition to the proposed arrangements in our July 2024 submission, this application supports our management of these risks and uncertainties through standard and 'extraordinary' risk allowances. There is also significant risk out with our control around the timing of delivery for areas of this programme. We are seeking confirmation that a mechanism is put in place to ensure allowance continuity where phasing of projects changes across RIIO-ED2 and RIIO-ED3, to ensure that transitioning from one price control period to the next does not impact our ability to deliver these works. Finally, we have included provision for the closely associated indirect costs we incur as we prepare and deliver interventions under HOWSUM, in line with the treatment of these costs defined under the Indirects Scaler.

Indicative RIIO-ED3 projects

We will continue to develop our proposals for the Hebridean, Orkney and Shetland island groups, and have already engaged with stakeholders from all island groups. These will build on our existing strategic plans and ensure we can continue our momentum into RIIO-ED3.

At this time, we anticipate our RIIO-ED3 application will comprise the following elements, subject to further enhancement:

- **Islay and Jura**
    - An additional 33kV circuit from Port Ann GSP to Knocklearach on Islay, including a second 33kV circuit between Islay and Jura.
    - Installation of a 33kV auto-close scheme at Port Ellen.
- **Orkney islands**
    - Confirmation of the key driver for Orkney development (i.e. whether generation export or demand-led) as part of our RIIO-ED3 submission. This will inform whether additional

2 Survey Details | Gremista GSP (Shetland) Strategic Development Plan - Draft for Consultation

transmission capacity or 66kV upgrades will be needed in RIIO-ED3 and beyond. Our RIIO-ED3 proposals will then contain the appropriate work.

- **Mull, Coll and Tiree**
    - A new 33kV circuit between Tullich switching station and Lochdonhead primary substation on Mull.
    - A second 11kV cable between Mull and Coll.
    - A replacement solution for Tiree Power Station to undertake load management. This may be through a third-party proposal, e.g. battery.
- **Outer Hebrides**
    - A second 33kV cable between Ardmore and Harris GSPs.
    - A new 33kV circuit between Clachan switching station and Harris GSP.
    - Proposals to utilise the Ardmore - Loch Pooltiel submarine optimisation loop to provide long term resilience to both Skye and the Outer Hebrides.
- **Shetland**
    - Proposals will build on our work in the finalised SDP and more detailed optioneering in 2025.

January 2025 application overview

We are therefore seeking funding for four discrete elements in this application.

- Carradale – Port Ellen 33kV network reinforcement: **installation of two new 33kV circuits between Carradale GSP and Port Ellen, with associated substation works.** This work is planned to be delivered by 2028. Our funding request includes risk and indirect cost provision proportionate to the activities.
- Thurso South – St Margaret's Hope 33kV circuit: **installation of a new circuit between Thurso South GSP and South Ronaldsay via John O'Groats**. This circuit will be installed as a 66kV construction to allow future conversion to 66kV as required. This work is planned to be completed in 2028/29. Again, our funding request includes risk and indirect cost provision.
- **Additional development funding allowance to progress the remainder of development works required for delivery in RIIO-ED2 and to enable delivery in RIIO-ED3.** This includes ongoing development work for Thurso – South Ronaldsay to be delivered over both price controls, as well as development activities to enable RIIO-ED3 delivery of works including a new circuit from Port Ann GSP to Knocklearach on Islay, development of an additional Skye – Harris circuit, progression of a new circuit between Tullich and Lochdonhead, and development work associated with replacement of the DEG on Tiree. SHEPD has identified that the existing £20.63m of ex-ante allowance for HOWSUM development activities will not sufficiently cover all identified development costs within RIIO-ED2. This additional development cost amounts to a total additional development request of [redacted].
- **Funding for fuel and carbon costs to cover the forecast increased operations of DEG in the Outer Hebrides.** This is due to significant transmission outages associated with network upgrade works on the Outer Hebrides and Skye in RIIO-ED2, at a cost of [redacted].

The total allowance adjustment requested in this application is £158.59m, summarised in Table 1. More detail is provided in the Adjustment Summary section.

Total adjustment summary (£m, 2020/21 price base)	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**Total**
January and July 2024 applications - CAI adjustment	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Islay - Jura adjustment	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Orkney adjustment	-	-	-	[redacted]	[redacted]	[redacted]
Outer Hebrides and Skye adjustment	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Mull – Coll - Tiree adjustment	-	-	-	-	[redacted]	[redacted]
Whole system analysis adjustment	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Total adjustment:	**-**	**-**	**5.98**	**31.87**	**120.73**	**158.59**

Table 1: Total allowance adjustment summary

MEETING OFGEM'S REQUIREMENTS

Structure of this application

Our application consists of:

- a core narrative document developed to address the requirements of Ofgem's Re-opener Guidance for all recommended interventions included in our application, and
- appendices consisting of Engineering Justification Papers (EJPs), deterministic Cost Benefit Analysis and Common Evaluation Methodology Cost Benefit Analysis assessing the recommended interventions for each island group.

The structure and outline content of this application is illustrated in Figure 11.

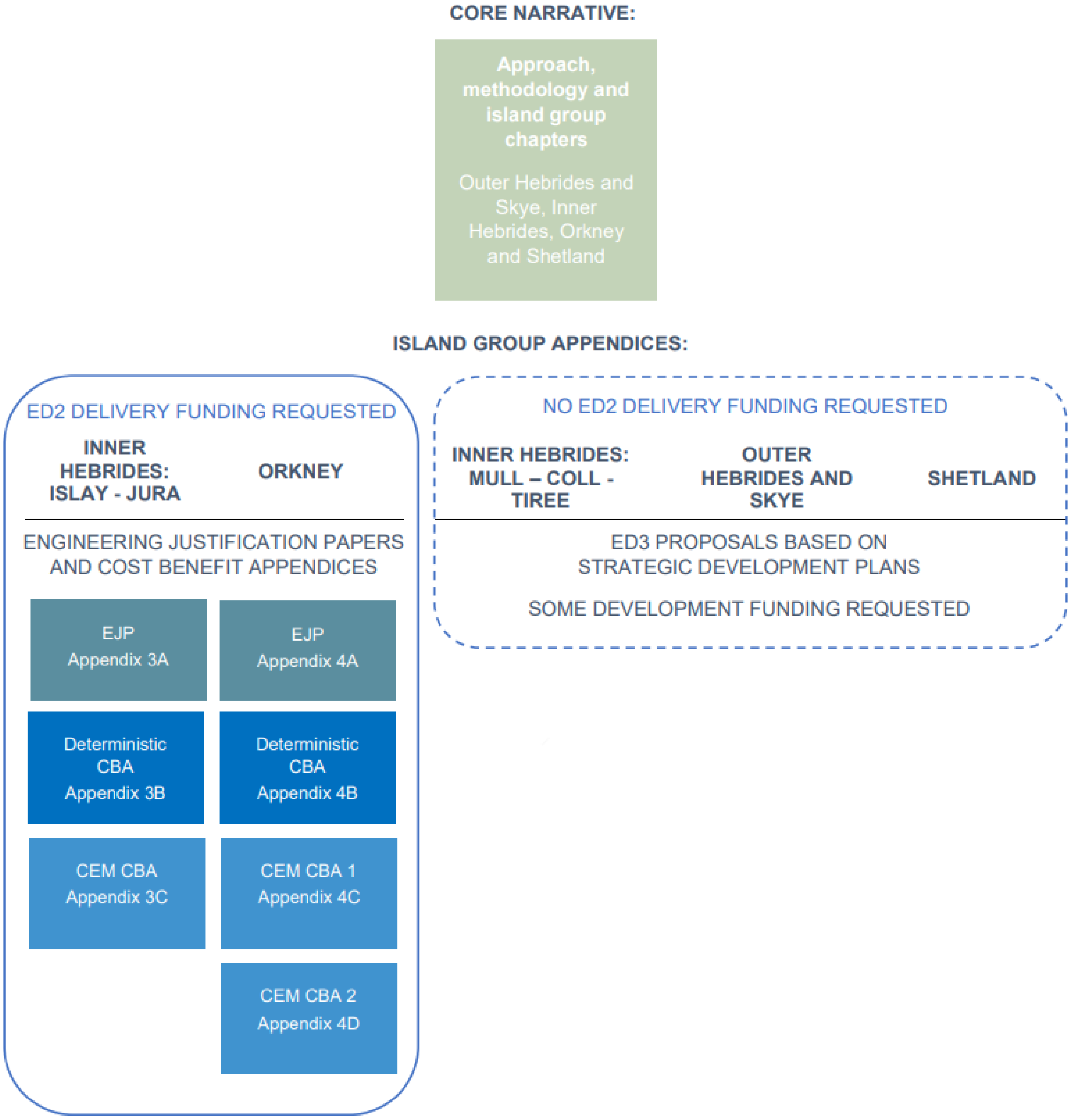

Figure 11: January 2025 HOWSUM application structure

Ofgem re-opener requirements

Table 2 sets out how we meet Ofgem's Re-Opener Licence requirements in this application.

Ofgem Re-Opener Licence requirement	Requirement met?	How addressed
(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 submarine 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	✓	SHEPD has incurred or expects to incur costs for development activities and interventions on the Outer Hebrides – Skye, Orkney, Mull, Coll, Tiree, Islay and Jura.
(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; or	✓	This application includes interventions associated with ensuring security of supply in the Scottish islands, demonstrating efficient whole systems considerations have been taken into account.
(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 3.2.105(a); and	✓	This application includes interventions associated with the outcomes of whole system analysis in the Scottish islands to contribute to net zero carbon targets, reducing emissions through reducing reliance on diesel generation and facilitating decarbonisation of island industries, and ensure long-term security of supply.
the change in those costs in paragraphs 3.2.105(a) or 3.2.105(b) exceeds the Materiality Threshold and are not otherwise funded by the special conditions.	✓	The costs incurred or expected to be incurred exceed the Materiality Threshold (£2.26m).

Table 2: Mapping Ofgem's re-opener licence requirements

Table 3 sets out where we meet Ofgem's Re-Opener Guidance requirements in this application.

Ofgem Re-Opener Guidance requirement	Requirement met?	Where addressed
Needs Case and Preferred Option	✓	Overarching approach summarised in Sections and 2; project-specific information summarised in Sections 3, 4, 5, 6, and 7; detail in island EJPs and CBA. Overarching approach summarised in Sections and 2; project-specific information summarised in Sections 3, 4, 5, 6, and 7; detail in island EJPs and CBA.

Ofgem Re-Opener Guidance requirement	Requirement met?	Where addressed
Stakeholder Engagement and Whole System Opportunities	✓	Overarching approach summarised in Section 2.2; project-specific information summarised in Sections 3, 4, 5, 6 and 7; detail in island EJPs.
Cost Information	✓	Overarching approach summarised in Section 2.6; project-specific information summarised in Sections 3, 4, 5, 6 and 7; detailed in island EJPs and CBA.
Cost Benefit Analysis and Engineering Justifications	✓	Overarching approach summarised in Sections 2.3 to 2.7; project-specific information summarised in Sections 3, 4, 5, 6 and 7; detailed in island EJPs and CBA

Table 3: Mapping Ofgem's Re-Opener Guidance requirements

Summary of bilateral engagement

This re-opener application follows several years of engagement on the HOWSUM through its design, implementation into the RIIO-ED2 framework, and the January and July 2024 applications. Key areas of focus and outcomes to date are summarised in Table 4.

Engagement (date)	**Scope**	**Discussion and outcomes**
September 2023 to January 2024	Approach and recommendations of January 2024 application	SHEPD shared methodology; needs cases; optioneering, technical, delivery and commercial considerations; stakeholder engagement; costs and CBA; and recommendations.
January to July 2024	Supplemental queries on January 2024 application; sharing approach and recommendations of July 2024 application	Working through SQs on January 2024 application. Technical, delivery and commercial, and costs and CBA updates for July 2024 application.
July 2024 to November 2024	Supplemental queries on July 2024 application	Working through SQs on January 2024 application.
25 and 17 November 2024	Cost risk for large projects; approach and methodology for January 2025 application	Discussion of specific items to be covered in January 2025 CBA (including decarbonisation of stations; transmission interactions; phasing of interventions). SHEPD emphasised continuation of cost risk for future RIIO-ED2 HOWSUM projects.
6 December 2024	Senior Ofgem-SHEPD bilateral	SHEPD shared concerns on cost risk for Skye - South Uist and future RIIO-ED2/3 projects, and discussion on timing of Ofgem Skye – South Uist decision given requirement to place contracts in early 2025.
December 2024 to January 2025	Draft Determinations for Skye-Uist project	Engagement on Ofgem's consultation on its Draft Determinations for our Skye – South Uist recommendations.
16 January 2025	Approach and recommendations of January 2025 application	SHEPD shared overview of methodology; needs cases; optioneering, technical, delivery and commercial considerations; stakeholder engagement; costs and CBA; and recommendations.

Table 4: Key bilateral engagement on HOWSUM

HOWSUM submission phasing

We have phased interventions for the Scottish islands across the HOWSUM re-opener windows based on the timing of need, driven primarily by asset condition for the January 2024 application, and latterly by load drivers. This phased approach has been supported by stakeholders at our webinars and bilateral meetings.

	January 2024 re-opener		July 2024 submission		January 2025 re-opener	
	Needs case, technical solutions	Costs	Needs case, technical solutions	Costs	Needs case, technical solutions	Costs
OUTER HEBRIDES						
Skye – South Uist	✓	-	-	✓	-	-
Skye – Harris 2	-	-	-	-	-	✓ *
South Uist - Eriskay	✓	✓	-	-	-	-
Eriskay-Barra	✓	✓	-	-	-	-
Harris – North Uist	-	-	-	-	-	-
INNER HEBRIDES						
Carradale – Port Ellen 1	-	-	-	-	✓	✓
Carradale – Port Ellen 2	-	-	-	-	✓	✓
Port Ann – Knocklearach	-	-	-	-	-	-
Mainland – Kerrera – Mull	-	-	-	-	-	✓ *
ORKNEY						
Pentland Firth East 3	✓	✓	-	-	-	-
Thurso – South Ronaldsay	-	-	-	-	✓	✓
Thurso – Scorradale (PFW)	-	-	-	-	-	-
Thurso – Scorradale (PFE)	-	-	-	-	-	-
SHETLAND						
Gremista GSP	-	-	-	-	-	-

* Development funding only – full proposals to be brought forward in ED3 Business Plan

Table 5: HOWSUM re-opener application submission phasing

Drivers for phased submissions

For the Skye – South Uist project, we submitted the needs case and preferred options first and followed up with the formal cost element later in 2024 after starting the procurement process. We believe there is a need for this staged approach for higher value projects going forward, providing a framework for Ofgem to understand the drivers for the work, to assess that our technical solutions are least regrets activities and the most efficient solutions, and allowing time for procurement processes to identify costs for high value projects in a volatile market. Such an approach will help manage cost risk which ultimately reduces consumer costs. We will engage with Ofgem on this approach in our RIIO-ED3 preparations.

Phasing to 2050

Our whole system assessments for the Scottish islands take a 2050 outlook and identify interventions across that timeframe phased according to when a given need arises. These tend to be more certain in the short term, particularly where we rely on demand forecasting to understand the timing of need. We will include our specific interventions for RIIO-ED3 and beyond in future business plan submissions. However, to avoid delays in progressing this work, we require additional development funding to cover early activities such as desktop analysis, submarine route surveying, route design and other procurement activities. Our forecast indicates that we will use the existing HOWSUM Development Fund for previously identified RIIO-ED2 projects, we have therefore included a development funding request in this application to cover additional development costs for those projects to be delivered in RIIO-ED2, across RIIO-ED2 and RIIO-ED3, or which require work now to be delivered in RIIO-ED3. We also intend that our RIIO-ED3 recommendations form the basis for our island proposals in our RIIO-ED3 Business Plan. We request, as part of their determination, Ofgem provide commitment to this approach and the implications for our future RIIO-ED3 regulatory submission.

Related documents

Ofgem Final Determinations[3] including SSEN Annex

SSEN Business Plan[4] including Supporting the Scottish Islands chapter

SHEPD Special Licence Conditions[5] specifically Special Condition 3.2, Part O

SHEPD January and July 2024 HOWSUM applications[6]

Ofgem Draft Determinations for Skye – South Uist[7]

Draft Strategic Development Plan – Port Ann and Carradale[8]

Draft Strategic Development Plan – Thurso South GSP[9]

Draft Strategic Development Plan - Taynuilt[10]

Draft Strategic Development Plan – Outer Hebrides and Skye[11]

Draft Strategic Development Plan – Shetland[12]

Application contact point

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landel.c.johnston@sse.com, rachel.kettles@sse.com and DistributionRegulation@sse.com

01738 342 447

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3 RIIO-ED2 Final Determinations | Ofgem

4 Our RIIO-ED2 Business Plan - SSEN

5 Decision on the proposed modifications to the RIIO-2 Electricity Distribution licences | Ofgem

6 Whole system energy solutions for the Scottish Islands - SSEN

7 RIIO-2 Re-opener: Scottish and Southern Electricity Network's 2024 Skye-Uist Project | Ofgem

8 Survey Details | Port Ann and Carradale Grid Supply Points Strategic Development Plan Consultation. Finalised published SDPs will be available on our publications page here: Publications & Reports - SSEN

9 Survey Details | Thurso South Grid Supply Point Strategic Development Plan Consultation

10 Survey Details | Taynuilt Grid Supply Point Strategic Development Plan Consultation

11 The Outer Hebrides and Skye SDP will be published in spring 2025 - see DSO Consultation Library - SSEN.

12 Survey Details | Gremista GSP (Shetland) Strategic Development Plan - Draft for Consultation

ADJUSTMENT SUMMARY

Table 6 provides a detailed breakdown of the allowance adjustment for this re-opener application. Please see the following and specific referenced sections for more information.

Adjustment summary (£m, 2020/21 price base)	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**Total**
CAI costs - January 2024 and July 2024 applications[1]						
January 2024 application	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
July 2024 application	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
CAI adjustment	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Total Islay-Jura forecast[2]	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Delivery costs[3]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development costs (pre-funded)[4]	*0.00*	*0.00*	[redacted]	[redacted]	[redacted]	[redacted]
Development costs (request)[5]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Standard risk allowance[6]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Extraordinary risk allowance[7]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
CAIs[1]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Islay-Jura adjustment	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Total Orkney forecast[2]	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Delivery costs[3]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development costs (pre-funded)[4]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development costs (request)[5]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Standard risk allowance[6]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Extraordinary risk allowance[7]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
CAIs[1]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Orkney adjustment	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Total Outer Hebrides and Skye forecast[2]	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Delivery costs[3]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development costs (pre-funded)[4]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development costs (request)[5]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Standard risk allowance[6]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Extraordinary risk allowance[7]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
CAIs[1]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Additional outage costs	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Outer Hebrides and Skye adjustment	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Total Mull, Coll and Tiree forecast[2]	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Delivery costs[3]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]

Adjustment summary (£m, 2020/21 price base)	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**Total**
Development costs (pre-funded)[4]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development costs (request)[5]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Standard risk allowance[6]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Extraordinary risk allowance[7]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
CAIs[1]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Orkney adjustment	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Total whole system analysis - all islands forecast[8]	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Delivery costs[3]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development costs (pre-funded)[4]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development costs (request)[5]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Standard risk allowance[6]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Extraordinary risk allowance[7]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
CAIs[1]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Whole system analysis adjustment	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL ADJUSTMENT	**0.00**	**0.00**	**5.98**	**31.87**	**120.73**	**158.59**

1. CAI costs are calculated as 10.8% of total project costs, after addition of project risk allowances. These were not included in our January and July 2024 applications and are therefore included here. See Section 2.6.5 and the island chapters for detail. CAIs do not apply to the additional DEG outage costs for the Outer Hebrides.

2. 'Total forecast' means all project costs (including development costs, capital and operating costs, risk and CAIs) before the deduction of any applicable HOWSUM development funding baseline allowance.

3. 'Delivery costs' are project costs before the addition of development, risk and CAI costs.

4. 'Development costs (pre-funded)' is the amount of development costs which has been covered by the existing HOWSUM development funding baseline allowance of £20.6m. Within our cost analysis this has been applied to reduce the funding request for development costs for each island group, up to the point at which it is fully utilised. Any additional development costs beyond this allowance are set out at 'Development costs (request)' and have been included in our funding request. See Section 2.6.6 and the island chapters for detail.

5. 'Development costs (request)' is the amount of additional development funding required to progress the relevant island interventions, after the HOWSUM development funding baseline allowance has been applied. See Section 2.6.6 and the island chapters for detail.

6. The standard risk allowance covers foreseeable and fairly well understood types of risks. See Section 2.7.7, the island chapters and our risk registers for detail.

7. The extraordinary risk allowance covers [redacted] It is applied as [redacted] of 'delivery' costs, after addition of CAIs. See Section 2.7.7 and island chapters for detail.

8. These costs are for whole system analysis and embedded generation assessments throughout RIIO-ED2, including to inform the delivery of RIIO-ED3 and 2050 whole system plans.

Table 6: Detailed total allowance adjustment summary

1. INTRODUCTION

1.1. Background to HOWSUM and this workstream

1.1.1. RIIO-ED2 Business Plan and Ofgem determinations

We submitted proposals to Ofgem for the North of Scotland region in our RIIO-ED2 Business Plan, including HOWSUM, to provide for flexible adjustment of cost allowances for investment in submarine cables and whole system investment options that aim to increase resilience, and reduce our reliance on island DEG during RIIO-ED2 and beyond.

In the RIIO-ED2 Final Determination Ofgem rejected all of these proposed bespoke mechanisms except HOWSUM, and removed funding for all HOWSUM-related interventions from SHEPD's proposed baseline allowances.[13][14] Instead, Ofgem determined that HOWSUM would be the route for funding approved interventions, and confirmed the provision of £20.6m (2020/21 prices) development funding for defined HOWSUM whole system analysis and pre-construction costs to support the timely progression of projects.

1.1.2. Approach to island groups

For the purpose of our analysis, we have considered the Scottish islands in a number of main groupings, illustrated in Figure 12:

- the Outer Hebrides, in orange, comprising the main islands of Lewis, Harris, North and South Uist, Benbecula, Eriskay and Barra as well as a number of smaller islands;
- Orkney, in purple, the main islands and stretches of water relevant for the purpose of this application being Mainland Orkney, Hoy, Shapinsay, South Ronaldsay and the Pentland Firth between Orkney and mainland GB;
- the Inner Hebrides, in green - for the purposes of our analysis we have considered the Inner Hebrides as two independent island groups due to independent networks supplying the respective groups of islands. We assess a group including Mull, Coll and Tiree, and a second group including Islay, Jura and Colonsay; and
- Shetland, in light green, comprising the main islands of Mainland Shetland, Yell, and Unst with a number of smaller inhabited islands making up the rest of the island group.

13 RIIO-ED2 Draft Determinations SSEN Annex (ofgem.gov.uk), Section 4 – June 2022

14 RIIO-ED2 Final Determinations | Ofgem

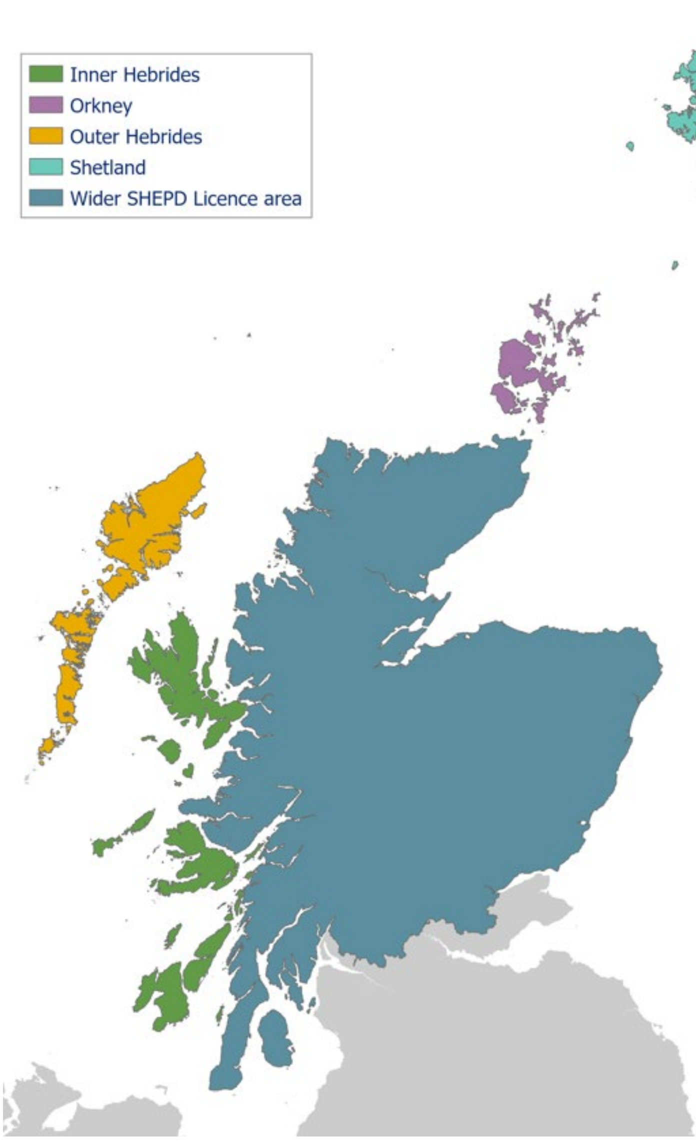

Figure 12: Scottish island group locations

Our approach to interventions takes account of the geographically and electrically distinct nature of the island groups. Recognising this, we are taking a similar approach to the island groups but are progressing each area separately, subject to specific island group drivers. This approach allows us to understand and leverage learning opportunities from our approaches, whilst allowing us to refine the options developed to meet the need of specific communities and industries. It also allows us to develop solutions that will facilitate decarbonisation of our operations on the island groups. Our whole system analysis and this application have been developed to identify the correct enduring solution for each island group, ensuring we can decarbonise our operations by the end of RIIO-ED3 in 2033. The allows us to meet aspirations of island communities, as well as Scottish and UK Government targets for net zero.

1.1.3. HOWSUM January 2024 application

Our January 2024 application[15] focused on near-term interventions driven primarily by asset health and resilience requirements, recommending additional or replacement cables for Eriskay – Barra, South Uist – Eriskay and Skye - South Uist, and for funding for the recently energised Pentland Firth East 3 cable, seeking a total of £46.28m. This excluded funding for Skye - South Uist, which we agreed with Ofgem would be confirmed by SHEPD in summer 2024 following initial procurement activities. Ofgem consulted on its minded to position to approve all interventions and most of the associated funding in September 2024, and published its Final Determinations in December 2024, approving £46.17m.[16]

1.1.4. HOWSUM July 2024 update

Our July 2024 update[17] requested funding for Skye – South Uist generated through initial market engagement. We confirmed a refined view of our preferred option including an additional "optimisation loop", with the overarching aim of mitigating delays to ensure the Skye –South Uist cable is in place as quickly as possible. We also shared significant commercial updates with Ofgem, specifically that our market engagement has confirmed costs which will be passed through to SHEPD by the supply chain as a result of market volatility. In response to this, we asked Ofgem for provision of an adjustment mechanism to allow us to submit incurred costs for assessment at a later date.

In its Draft Determinations on Skye – South Uist[18] Ofgem has proposed to provide £53.81m out of a total funding request of £68.36m, on the basis that it considers our preferred option is not the most optimal. We continue to recommend our preferred option and will engage with Ofgem on the justification for this over the coming weeks and in a formal response to the consultation.

Ofgem has also said it does not intend to provide a new mechanism in RIIO-ED2 for this purpose, and that cost fluctuations would be more appropriately dealt with through the totex incentive mechanism (TIM). In light of Ofgem's current position, we have instead included "extraordinary" risk allowances to cover this risk – see Section 2.7.7.2 and the island chapters for more detail.

We welcome a swift determination on funding for this project to expedite the next stages of our procurement activities and project implementation.

1.1.5. HOWSUM January 2025 application and 2050 horizon

This application takes a 2050 view for the island groups of Orkney and the Inner Hebrides, with an updated position provided on the Outer Hebrides. It also includes an update on our assessment of whole system requirements for the Shetland islands.[19]

The investments presented in this application include the near-term interventions required within RIIO-ED2 as well as works which are required in RIIO-ED3 and beyond. They are driven primarily through future demand and generation growth, but also account for both network resilience requirements and our emissions reductions strategy. We request funding for capital works taking place in RIIO-ED2, as well as development works taking place in RIIO-ED2, which includes activities to enable delivery of recommended projects across RIIO-ED2 and RIIO-ED3., In the context of our 2050 plans, which span

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15 SSEN publishes plans for the development of the Outer Hebrides' electricity network - SSEN

16 Final Determinations on RIIO-2 re-opener applications 2024: Electricity Transmission, Electricity Distribution and Gas Distribution | Ofgem

17 Whole system energy solutions for the Scottish Islands - SSEN

18 RIIO-2 Re-opener: Scottish and Southern Electricity Network's 2024 Skye-Uist Project | Ofgem

19 Through bilateral engagement with Ofgem at Final Determinations we confirmed that HOWSUM is not geographically limited to the Hebrides and Orkney, but may apply more widely to our North of Scotland licence area.

future price controls, we seek Ofgem commitment to funding relevant recommended projects in RIIO-ED3.

We recommend specific interventions required in RIIO-ED2 for Orkney Thurso South GSP, the islands of Islay – Jura, and Port Ann – Carradale GSP, and identify further work to be taken forward in RIIO-ED3 with associated estimated costs.

Through assessment of Mull – Coll – Tiree in the Inner Hebrides, for Shetland, and developing an updated outlook for the Outer Hebrides building on our previous applications, we have not identified specific interventions to be taken forward in RIIO-ED2, but we have mapped works required in RIIO-ED3 and beyond, and we also identify further RIIO-ED2 development funding requirements in associated with these areas (see Section 2.6.6). In addition to project development works this includes funding to undertake further whole system analysis and develop flexibility opportunities.

Our RIIO-ED3 Business Plan will reflect the continued development and implementation of the projects recommended here, taking account of appropriate updates, optimisation and refinements.

The specific drivers, needs cases, optioneering and recommendations for each island group are provided in the following island chapters and the accompanying EJPs and CBA.

2. ASPECTS COMMON TO ALL RECOMMENDATIONS

This section sets out aspects of our approach which are common to all island interventions. We detail project-specific information for each section in the individual island group chapters.

2.1. Alignment with business strategy

Our business strategy is focused on powering our customers and communities both today and tomorrow. This will ensure we are set up not just for this price control and the next but have a clear pathway to 2050. This is driving change across our business, particularly around our load investment plans. This section outlines the key aspects of our strategy relevant to development of this application. We provide more information on the specific approach and methodology in Section 2.3.

2.1.1. Building on insights from RIIO-ED2

Preparing the SHEPD RIIO-ED2 Business Plan was a multi-year process of gathering extensive stakeholder feedback through targeted engagement, coupled together with robust asset health data and DFES assessment. This was achieved through the use of the Common Network Asset Indices Methodology (CNAIM)[20] using the latest asset condition data sets held for submarine cables from inspections and surveys to inform the risk calculation for each cable expressed in terms of long-term monetised risk. The Business Plan concluded that proactive strategic investment is required on the submarine and islands networks of the Scottish islands.

Through our RIIO-ED2 Business Plan stakeholder engagement, our communities and stakeholders requested the actions set out in Figure 13.

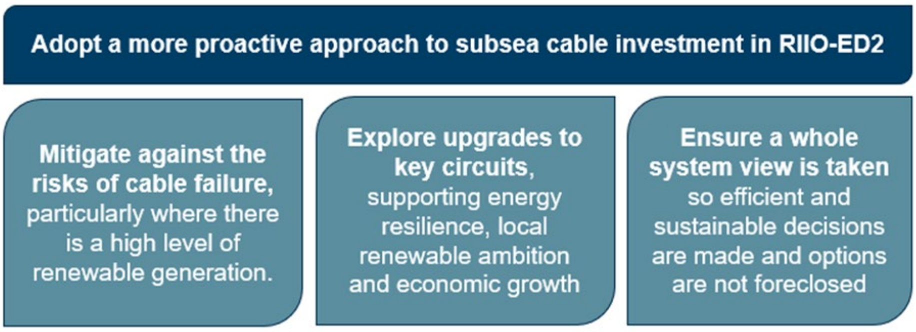

Figure 13: RIIO-ED2 Business Plan stakeholder engagement - approach to submarine cable investment

We have continued and deepened our HOWSUM-focused stakeholder engagement over the interim period, through webinars and meetings. Subsequent stakeholder feedback and insights are included in Section 2.2 and in the individual island chapters. A key requirement we focus on in this application is consideration of stakeholder needs. We achieve this through a whole system approach that also considers how we can remove our reliance on the existing fossil fuel DEG standby stations strategically

[20] DNO Common Network Asset Indices Methodology (ofgem.gov.uk)

positioned on specific islands. These currently provide the necessary back-up generation in the event of a submarine cable fault.

2.1.2. Taking a strategic approach to net zero

SSEN is taking a strategic approach in the development of its distribution networks. This will help to enable the net zero transition at a local level to the homes, businesses, and communities we serve. SSEN's Strategic Development Planning Methodology (SDPM) is our defined approach to achieve this. The aim of this methodology is to provide the capacity on the network to deliver net zero whilst retaining a clear focus on safety and reliability. We discuss this further in Section 2.3.

Factors considered in our approach include the need to take a 'flexibility first' approach, ensuring that we are using flexibility services appropriately to deliver efficient whole system solutions at the optimum time. We also recognise the importance of stakeholder evidence to ensure the network develops to meet the needs of our customers today and tomorrow, as discussed in Section 2.2. We have implemented this new approach when developing proposals relating to relevant RIIO-ED2 uncertainty mechanisms including the HOWSUM.

Our networks differ vastly across our licence areas, recognising the very different communities we serve. Whilst our overarching approach to strategic development is sufficiently broad to encompass most conditions there are specific requirements that warrant a more tailored approach. One such example is the submarine cable connections to our island communities. The SDPM accounts for this and notes that in such instances a cross-functional project group will be established, agreeing the specific scope of the work, and our approach to stakeholder input, depending on the unique conditions. In the case of Scottish islands, this has involved specific strategies around submarine cables, whilst accounting for demand and generation growth on the islands and continued security of supply. This is discussed further in Section 2.4.

We have also implemented our strategic approach in progressing our general Load Related Expenditure (LRE) activities. We have ensured close co-ordination of the LRE programme with HOWSUM. Common SDPs have been developed for each region. The LRE programme has focused on RIIO-ED2 developments limited to either the GB mainland system or on-island networks, and the HOWSUM work has incorporated these developments into its power system analysis. Further context on our SDPM and SDPs is provided in Section 2.3.

2.1.3. Commitments on emissions reductions

SSEN Distribution was the first DNO to set an accredited 1.5-degree Science-Based Target (SBT) for greenhouse gas (GHG) emission reduction in October 2021, underpinning our ambitious programme of activities to drive down our carbon impact and to support others as they reduce theirs, such as the whisky industry. Overall, our SBTs aim for a 55% reduction in GHG emissions by 2033, meaning at least a 35% reduction in our combined Scope 1 and 2 emissions in RIIO-ED2. As a business we will meet net zero by 2045 at the latest.

Our RIIO-ED2 Environmental Action Plan (EAP)[21] commits us to reduce reliance on DEG, exploring local solutions and flexibility opportunities from the start of RIIO-ED2, to enable the removal of reliance on DEG in RIIO-ED3 and beyond. The ambition detailed in this application is critical to enabling that flexibility and achieving those local solutions. In order to meet net zero, we cannot continue with diesel generation and, therefore, must find suitable alternatives. This is more important than ever as increasing storm activity, due to climate change, leads to more faults and DEG station running times.

21 Sustainability - SSEN

We are currently assessing the operational feasibility, and costs and benefits, of use of Hydrotreated Vegetable Oil (HVO) at our embedded stations (Section 6.2.1). HVO should be used with caution and as purely a transition fuel with lower emissions than diesel, providing a short-term step, but not a solution, on our decarbonisation journey as we explore the deployment of innovative technological solutions alongside the required local solutions and flexibility services. HVO is not a long term solution and we need regulatory funding to achieve the enduring decarbonisation of our DEG stations to deliver net zero for the environment and the communities we serve.

2.2. Stakeholder engagement

This section describes the stakeholder engagement that has been implemented to inform this submission, from RIIO-ED2 business planning stage to date.

2.2.1. RIIO-ED2 Business Plan engagement

As part of our RIIO-ED2 planning we carried out a programme of enhanced engagement to assess stakeholder appetite for us to invest during RIIO-ED2 to improve the condition of our network assets and the quality of supply for customers during RIIO-ED2 and beyond.

As we finalised our RIIO-ED2 Business Plan, we refined our Scottish Islands Strategy and outputs, which involved direct testing of the strategy, outputs and costs with over 200 island stakeholders. Outputs from this work specifically focused on supporting our remote communities include the following aspects:

- Stakeholders were highly encouraged with our increased investment in submarine cable connectivity between islands and the GB mainland.
- While stakeholders supported the investment in submarine cables to improve island connectivity, it was noted that storage and flexibility should be considered to reduce the need for network reinforcement on Scottish islands and improve the reliability of supply.
- Stakeholders thought the ambition and comprehensiveness of the Supporting the Scottish Islands strategy and outputs had built on the lessons from RIIO-ED1 and represented value for money.
- Stakeholders sought enhanced engagement on future network capacity and resilience of supply options; ensuring that local communities are part of the consultation process, including on innovation opportunities for reducing costs and replacing diesel generation.
- Based on a deep dive session with stakeholders on the Scottish Island Strategy and costs, stakeholders supported its comprehensiveness noting that engagement was a step up from RIIO-ED1 performance and raised areas for further refinement:
  - Application of how the Uncertainty Mechanism would be applied suggesting cost/benefit and net zero should be considerations.
  - Enhanced ambition to facilitate more renewable generation from the islands and whole system solutions.

In response to this feedback, we added the Hebrides and Orkney Whole Systems Uncertainty Mechanism to our strategy, as an optimal approach to realise customer value by providing flexibility to develop integrated whole systems solutions as we work with stakeholders to identify and value opportunities.

Our HOWSUM approach and recommendations build on the insights from this earlier stage of engagement. We have assessed all Scottish island groups and, building on our RIIO-ED2 baseline projects for the islands, recommend a programme of implementation of submarine cable links from RIIO-ED2 onwards where efficient and beneficial to do so. Our HOWSUM methodology develops recommendations which are cost / benefit and Strategic CBA-led (Section 2.3), using the latest demand and generation outlook to 2050, and sizes network assets on this basis. We have assessed whole system options taking account of wider network interactions including transmission developments.

We assess the benefit of flexibility services and its ability to defer network investment using our Common Evaluation Methodology (CEM) tool (Section 2.3.3.1), and our Strategic Development Planning process incorporates focused engagement in the development of local energy plans (Section 2.3).

Further key insights from our early RIIO-ED2 engagement are summarised in the of our RIIO-ED2 Business Plan.[22]

2.2.2. Engagement during RIIO-ED2

Our approach to engaging with stakeholders on HOWSUM has been aligned to the stages of the SDPM process as described in Section 2.3.

2.2.2.1. Identifying future system needs

Recognising the unique nature of Scottish islands, we have worked with Regen[23] to specifically engage with islands stakeholders and communities. This includes both bilateral discussions with a wide range of stakeholders as well as Regen joining SHEPD-hosted island stakeholder webinars. From this Regen have drawn up specific insights on the developments of each island group. We have used these to inform both development of future system needs on the islands and the development of options, critically including the timing of when these options will be needed.

Regen has collated its evidence through analysis of existing and historical project pipeline data and scenario projections, online research, direct engagement, and as part of SHEPD's broader island engagement. This involves the following insights:

- Marine vessel decarbonisation / electrification
- Whisky distillery decarbonisation
- Any stand-out commercial developments
- Relevant considerations from marine and offshore wind industry developments on the islands

We found that we required further data relating to both whisky distillery and marine vessel decarbonisation as the two most critical elements of industrial decarbonisation on the islands and engaged further with relevant stakeholders in both industries. We received more information on whisky distillery decarbonisation following discussions with the Scotch Whisky Association (SWA), the Islay Energy Trust and individual distilleries. These have fed into the methodology for forecasting future demands which is described in this section. Whilst we have data on proposed connections for the maritime industry, longer term projections are harder to quantify. This work is now being progressed as

22 See chapter *Supporting the Scottish Islands*, SSEN-RIIO-ED2-final-business-plan.pdf.

23 Home - Regen

part of the SeaChange Strategic Innovation Fund project[24] and we will use the project's outputs to feed into our longer-term plans for the islands.

2.2.2.2. Developing and assessing options

When developing high level SDPs (see Section 2.3.2.3), we have engaged with stakeholders through both stakeholder events and a formal consultation process. The plans have given stakeholders visibility and an opportunity to feedback on the network options that were being developed and assessed for each island group. The feedback has been reviewed and assessed using a RICE (Reach, Impact, Confidence, Effort) approach to ensure that views are effectively analysed and incorporated into detailed option development.

As we moved through the detailed optioneering process, through to refinement of a preferred option for each island group, engagement sessions were held with stakeholders to provide visibility and gather further feedback on the proposals that make up this submission. We will continue to engage with stakeholders, with webinars planned in Spring 2025 to provide stakeholders with a progress update.

Further details on the insights gathered through these exercises can be found in the island specific sections of this document. We have applied stakeholder feedback to refine our approach and methodology for the Scottish islands, detailed in the following sections. Further details on the insights gathered through these exercises can be found in the island specific sections of this document.

2.3. The Strategic Development Planning Methodology

2.3.1. Overarching process

In Section 2.1.2 we introduced our Strategic Development Planning Methodology (SDPM).[25] This section provides further context on the methodology and each of the underpinning stages.

The SDPM consists of several stages which enable us to understand the future local energy landscape, assess the need for change and develop and assess options to resolve these needs. The high-level approach, as applied to HOWSUM, is shown at Figure 14. We have also noted bespoke activities developed for the Scottish island and HOWSUM context, discussed further in Section 2.4.

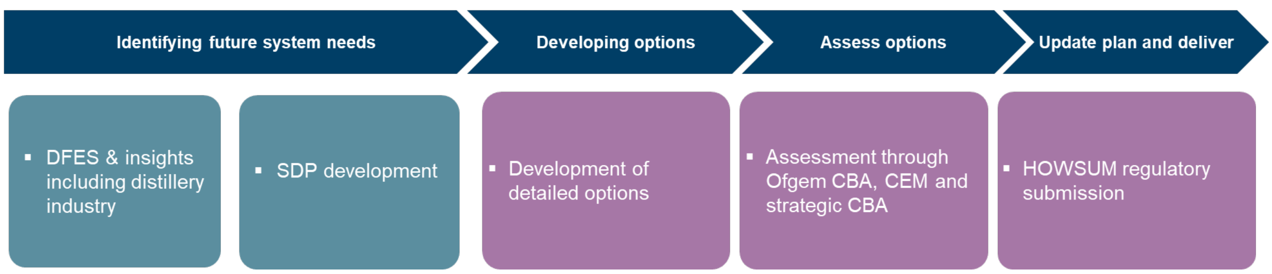

Figure 14: Strategic Development Planning process as applied to HOWSUM

2.3.2. Developing the needs case

24 SeaChange01 | ENA Innovation Portal

25 Our strategic network planning process - SSEN

2.3.2.1. Distribution Future Energy Scenarios and insights

Demand forecasts are derived from our DFES. The scenarios are revised annually by working closely with stakeholders to understand their future energy needs to 2050. We also consider our connections pipeline to inform these forecasts. The DFES considers four credible pathways to achieving net zero by 2050. We consider all four scenarios from a system needs perspective, but currently apply the Consumer Transformation (CT) scenario - a credible 'best view' of future requirements - as the basis of our Strategic Development Planning process. We test the sensitivity of this model through use of the other three scenarios.

For HOWSUM we have built on this process through our work with Regen to understand the specific drivers relating to each of our island groups.[26] Regen's work has allowed us to more greatly understand the scope of industrial decarbonisation on the Scottish islands. This has led to further work quantifying the impacts of decarbonisation of the whisky industry which has helped shape our proposals, in combination with the initiation of our Seachange innovation project[27] with the European Marine Energy Centre (EMEC)[28] and the Power Networks Demonstration Centre[29] investigating maritime decarbonisation.

2.3.2.2. Assessing asset condition

As part of the development of the network investment needs cases, consideration is given to existing asset condition and their ability to continue to operate over the assessment period. This is undertaken through the review of asset condition data and associated asset health index bandings produced as an output from our use of the Common Network Asset Indices Methodology (CNAIM), which is the methodology approved for reporting network risk due to asset health by Ofgem. This modelling provides each individual submarine cable asset with individual health scores which are then reported in the appropriate health index bandings ranging between Health Index (HI) 1 to HI5. Cables which are noted as HI1 could be described as "New" with cables progressively deteriorating over their lifecycle until they reach HI5, considered at "End of Operational Life".

Typically, planned interventions would be undertaken on assets which fall into the HI5 category, following additional detailed assessments. These interventions usually take the form of replacement of the existing assets on similar routes. The sizing of new cables would be based upon future forecast demand and generation needs. These asset health- or condition-based investments are usually presented through the non-load baseline investment plans as part of each price control; but where the cables are strategic, supplying whole island groups, they will undergo a whole system assessment as with this application.

As part of the assessment of the HOWSUM island groups and the main strategic supply cables, [redacted]. All other island main supply cables are currently deemed to be in relatively good condition in comparison, under the methodology.

2.3.2.3. Strategic Development Plans

26 Whole system energy solutions for the Scottish Islands - SSEN

27 SSEN's nature and shipping innovation projects win £1m in new development funding - SSEN

28 EMEC: European Marine Energy Centre

29 Home - PNDC

To ensure that we have the right long-term approach to investment, we have embarked on setting out SDPs for all Grid Supply Points (GSPs) across our network, developed under our SDPM process. The concept of the SDP is to set out a vision for the development of the specific network areas associated with the GSP out to 2050. The SDPs bridge the gap between the DFES and projects entering the Distribution Network Options Assessment (DNOA) process. They utilise the DFES and stakeholder insights from local spatial plans to translate forecasts into long-term system needs. We consult on draft SDPs; providing an opportunity for our stakeholders and customers to offer feedback and insight, which we then look to incorporate for final publication on our website. Key stages in the full process are detailed at Figure 15.

This ensures that the interventions we are taking today align to a longer-term plan which is vital as, with rapidly increasing connections to the network, it can be easy to follow a reactive approach to network development. It also enables our stakeholders to understand the likely development of the network over time, based on what they are collectively telling us. This provides transparency and prompts conversations around how stakeholder future needs might drive changes and lead to constructive iteration of those plans. The timing of various investments set out in the SDPs can also facilitate early conversations around planning, land access and land purchase. This can help ensure that when future investments are required, they can be delivered faster.

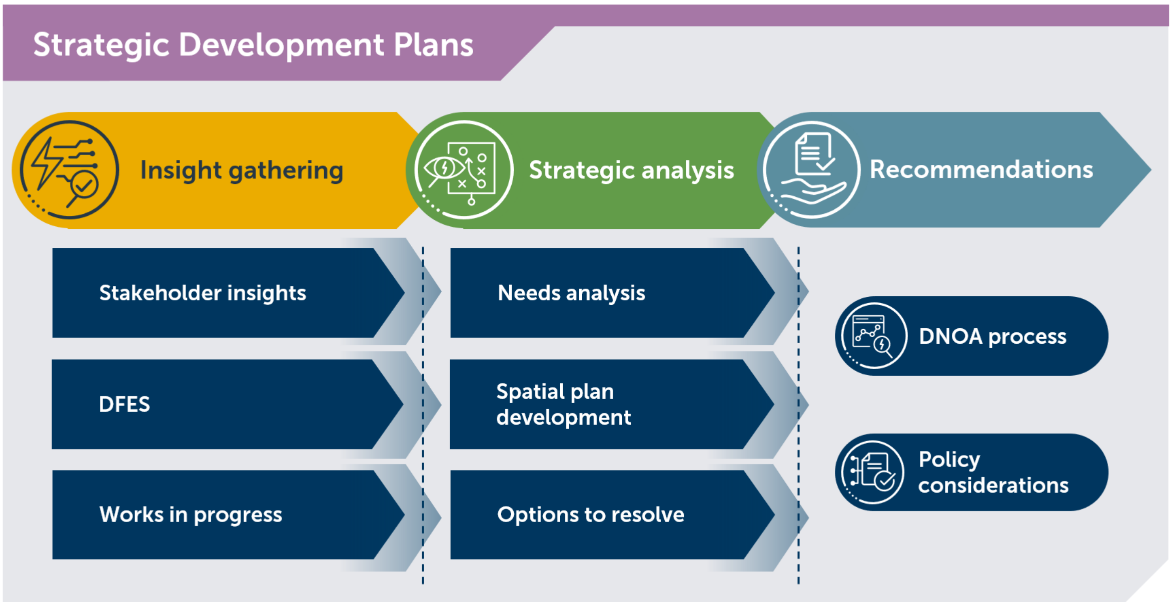

Figure 15: Detail of Strategic Development Plan structure

SDPs are living plans reviewed on an annual basis as our DFES forecasts are updated, and act as blueprints to assist our connections and planning teams with future network development. Draft SDPs being consulted upon[30] and finalised SDPs[31] are available to review on our website.

2.3.3. Developing options to resolve

Led by our Distribution System Operator (DSO) directorate, a cross-functional team is established to review the high-level options developed through SDPs to ensure they are technically competent. This

30 DSO Consultation Library - SSEN

31 Publications & Reports - SSEN

includes both delivery and operability feasibility and power system analysis, resulting in a range of options to be assessed including potentially both network and non-network options.

2.3.3.1. Consideration of flexibility opportunities

SSEN's DSO directorate ensures that we have considered flexibility to help efficiently deliver capacity on our networks. When considering the potential opportunity for flexibility services, we examine three key aspects:

1. **Whether flexibility will resolve the technical need**

The technical assessment ensures we are only using flexibility services where they will safely support the management of the network. In some uses cases this might not be possible, for example management of transient fault currents on the system, or demand restoration for fault situations. In these cases, the feasibility of flexibility services to resolve the issue has been discussed in detail before being ruled out.

2. **The benefits of using flexibility services**

The Common Evaluation Methodology (CEM) tool is used to quantify the benefit of flexibility services and determine the number of years for which flexibility services should be used to defer the identified reinforcement.

3. **The ability to procure the required flexibility service in the area**

This assessment considers whether we can procure flexibility services in the region. This includes looking at a range of factors including the portion of domestic and industrial customers, the number of forecasted Electric Vehicles (EVs) and any generation or storage facilities expected to be connected. These are combined with forecast flexibility participation rates based on data from all DSOs. This approach has allowed us to focus our market development on areas where we have confidence that we will secure the flexibility services we need. Without this assessment there would be a risk of limited participation providing partial volumes which we may ultimately not use, as we would need to accelerate the build solution to ensure the network remained secure.

For the Scottish islands we have enhanced this approach by issuing a Request for Information (RFI) for island flexibility services in August 2024. This has enabled us to understand the potential number or type of services that could be provided for use in Scottish islands. This exercise has not identified one specific location with significant volumes of flexibility resource that could be used to avoid the complete use of DEG or deferral of investment in RIIO-ED2 timescales. However, it has confirmed there is significant interest in participating in flexibility services in the islands, but investment would be required by individual parties which is difficult to justify without certainty of use and therefore income streams.

Of note is the potential for a stability service in the Outer Hebrides later in RIIO-ED2. This could help reduce the cost of DEG operation. We have previously attempted to procure this service, but failed due to lack of available companies that could meet the requirement. We now believe there is merit in revisiting this opportunity. This is described further in Section 2.3.3.1.

We continue to build the markets further, with planned actions outlined in the Flexibility Roadmap[32], and there are many actions we have taken over the last year in line with these aims. A particular focus has been on our processes, which has included moving to Overarching Agreements for our flexibility services[33] (with 21 different companies having signed this) and a new Flexibility Market Platform. This has allowed us to attract multiple Flexibility Service Providers with a range of discrete generation assets

32 ssen-flexibility-roadmap-2024.pdf

33 https://www.ssen.co.uk/globalassets/our-services/flexibility-services-document-library/slc31e-reports--statements/slc31e---ssen-2023-24-flexibility-services-procurement-report.pdf

and aggregated portfolios who are able to offer volume over the widest possible geographical areas and at significant scale.

2.3.4. Assessment of options

Technically feasible options are assessed through one or more of three CBA packages, depending on their characteristics:

- Deterministic (Ofgem) CBA: this compares the Net Present Value (NPV) of different technical options to determine the most efficient solution.[34]
- Common Evaluation Methodology (CEM): this tool allows us to assess where flexibility could be used as a more efficient option for capacity management (Section 2.3.3.1).
- Strategic CBA: this CBA considers a wider range of benefits that can be more difficult to monetise and allows us to assess different future load scenarios such that we can take a least worst regrets approach to investment. Below we provide more context on this CBA.

2.3.4.1. The Strategic CBA

A more strategic way of assessing network investment allows us to both consider the uncertainty in future network loads and also the wider benefits of a strategic approach. We achieve this through enhancing an industry standard tool, the Whole System CBA[35], to both take a least worst regrets approach to strategic investment and consider broader benefits. The Whole System CBA is already agreed for use in Ofgem's Coordinated Adjustment Mechanism (CAM) and so we are building on an already approved tool. We refer to this enhanced tool as the Strategic CBA.

The Strategic CBA leverages the Social Return on Investment framework developed by the ENA to assign a monetary value to economic, environmental, and social costs and benefits. It can help identify the optimum timing of an intervention by considering requirements under multiple DFES. It can also consider the size and scope of solution required, i.e. whether there is benefit on a broader, more strategic solution implementation, rather than an incremental approach. The Strategic CBA assesses which network option offers the 'least worst' regret across the four DFES given the uncertainty of future load growth. This approach does however not consider the probability of each of the different scenarios occurring and the NPV output from the tool is considered in conjunction with the 'least-worst' regret output.

The results of the Strategic CBA are broken down into three categories: costs/benefits to SSEN, costs/benefits to society and costs/benefits to customers. For each of these three categories, an overall benefit entered as a positive number and an overall cost is entered as a negative. The capex, operating expenditure (opex) and DEG costs used in the Ofgem deterministic CBA tool are represented in the costs/benefits to SSEN. The benefits to society and customers are calculated as follows.

The DFES technology projections can be used in the Strategic CBA to evaluate different benefits in the area impacted by the investment. Different investment decisions on timing and the solution proposed will enable different amounts of load to connect to our network at different points in time. The option chosen impacts the potential benefits for customers and society as well as the investment cost. When assigning benefits to investment options, the investment driver and impact of the work on available network capacity compared to the current capacity is considered to ensure the attribution of investment

34 RIIO-ED2 CBA Guidance

35 Whole energy systems – Energy Networks Association (ENA)

and benefit is reasonable. The benefit types are grouped into customer benefits and societal benefits and the benefit types built into the tool are listed below:

Customer benefits:

- Realised Connections – Demand
- Realised Connections – Generation
- Annual savings from enabling low carbon technologies

Societal benefits:

- Avoided (benefit) or incurred (cost) carbon emissions
- Avoided (benefit) or incurred (cost) air quality emissions
- Job creation (local economy stimulus)
- Annual savings from decarbonising transport
- Societal benefit of enabling schools
- Societal benefit of enabling affordable homes

For the costs/benefits associated with emissions, these may be positive or negative to represent avoided or incurred emissions respectively. If work which is required by a certain year to enable load growth is pushed back, this is accounted for in the tool through reducing the benefits assigned through the DFES values to represent the missed benefits of not enabling customers to connect at the time of need. We provide context in relevant island chapters on the specific cases where the Strategic CBA has been used.

2.4. Application of the SDPM to HOWSUM

When assessing the islands we focus on island-specific insights and forecasts consistent with our overall SDPM approach. We carry out this process through analysis of our knowledge of the relevant networks, through our System Planning and Connections activities, direct stakeholder engagement, and key insights work.

In terms of identifying future system needs, we focus on the business strategies listed in Section 2.1, taking account of the specific assets and arrangements in place. There is also an in-depth focus on whole systems impacts and interactions. Specific considerations for developing strategies for the Scottish islands are set out below.

2.4.1. Specific HOWSUM considerations

2.4.1.1. Decarbonisation of our diesel generation fleet

In Section 2.1.3 we provided an overview of our emissions strategy. For Scottish island groups this strategy has a significant interaction with the future of the existing DEG fleet.

Our DEG fleet

DEGs provide valued back-up supplies for the islands in the event of network outages. Our DEG units were established in the 1950s before the use of submarine cables as the main source of electricity to some island communities. Over time DEG units have evolved to be used as an essential alternative supply to submarine cables during outages and faults in these communities. Whilst acting only as a last resort, DEG units are currently required to ensure compliance with both Engineering Recommendation P2 (P2/8)[36] and the Distribution Code[37] on security of supply for these islands.[38] However due to the emissions produced by these units, developing long term solutions to eliminate reliance on DEG is important to remaining on the pathway to net zero and delivering a 1.5-degree carbon reduction pathway in line with our SBT commitments.

We have been engaging with the Scottish Government on use of diesel in back-up plant as they develop their Climate Change Plan and they are supportive of our work to remove reliance on diesel power stations.

In order to maintain resilience, in limited circumstances we are developing plans to replace embedded station engines. We are assessing the potential replacement of engines at Battery Point to a new location within an existing site in line with our RIIO-ED2 Business Plan, and funding agreed with Ofgem for this purpose. Any new engines will have better environmental performance and will be compliant with the Medium Combustion Plant Directive and other applicable environmental legislation, which is also likely to require abatement. This work will be carried out in co-ordination with the HOWSUM development work to ensure a co-ordinated strategy for the Outer Hebrides. In the short term, we have identified a specific need to utilise certain DEG more extensively than originally forecast in our RIIO-ED2 Business Plan, [redacted]. This has driven an additional funding request and is detailed further in Section 6.

Utilising third party services

As part of the HOWSUM process we have considered market-based solutions that can provide the necessary services. In August 2024 we published an RFI on potential flexibility services that could be obtained to support Scottish island needs. Through the RFI process no one area was identified as having sufficient sources of Flexibility Services to remove the need for the DEG. However, it may be possible to reduce the use of DEG with the complementary use of Flexibility Services. Part of the RFI process aimed to identify barriers to participation specific to this need set as the uncertainty of ongoing revenues can make the needed investment difficult to justify for individual entities. It also provided an action to continue to develop commercial services to increase the complementary and stacking nature of these services.

A previous attempt to procure a stability services on the Outer Hebrides had been unsuccessful as there was no provider who responded to the procurement activity who could meet the requirements. Such a service could help reduce the need for DEG operation at Battery Point and/or Loch Carnan. Since this procurement activity, development of projects by providers and increasing engagement with a range of participants on the islands means we believe the procurement may be more successful and as such we plan to tender for Flexibility Services early in 2025. As well as reducing operational costs and carbon emissions, such a service could also help set a pathway for long duration third party solutions.

Our approach to DEG in RIIO-ED2

We intend to reduce reliance on DEG in RIIO-ED2 through the plans put forward in the HOWSUM applications, however the embedded diesel sites remain integral and necessary assets as part of our network operations through the remaining RIIO-ED2 period. DEG currently play an essential role in providing alternative sources of supply for island customers during planned and unplanned network outages and will continue to do so until our longer-term strategic plans are delivered. [redacted]

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36 ENA EREC P2 Issue 8 (dcode.org.uk)

37 Specifically PO-PS-037 in Distribution Code Annex 1; Microsoft Word - Section 11 Notice - Schedule 2 - POPS037.doc (Ofgem.gov.uk)

38 For Lewis and Harris and also smaller parts of these networks, exemptions are in place.

[redacted]

Reliance on DEG will be reduced through the following HOWSUM proposals:

- Improving reliance of submarine cables by targeted replacement of those reaching the end of their asset life.
- Improved network resilience reducing the probability of DEG operation - this will be the case for the Orkneys and the Inner Hebridean island group of Islay, Jura and Colonsay.
- Developing proposals for RIIO-ED3 to further increase resilience through network and third-party solutions.
- Progressing the development of a flexibility service on the Outer Hebrides.

These impacts will deliver benefits when completed, predominately during RIIO-ED3. More information on specific plans for DEG are included in the island chapters.

Our longer-term strategy

Our proposals have been developed to remove reliance on DEG by the end of RIIO-ED3. This will allow our activities to meet emissions requirements. We see network investment as being the primary route to facilitate this strategy, however we have noted cases where the use of a DEG replacement, potentially through a third party solution, could produce a more efficient solution.

We will develop these longer-term proposals during the RIIO-ED3 business planning process This will include assessment of the potential of flexibility services on each island.

2.4.1.2. Maintaining future resilience to islands

We recognise that, going forward, customers are increasingly reliant on their electricity supply for a widening range of functions, including transport and heating. Supply resilience in the future should be maintained at the current standard at a minimum, and no demand customer should experience a detrimental impact to their supply as a result of our development proposals. [redacted]

This policy only applies to consideration of the loss of the connecting submarine cable(s), i.e. rather than the GB mainland network or on-island networks. Table 7 summarises this policy.

<table>
<tr><th>Forecasted 2050 group demand (CT)*</th><th>Relevant 2050 P2-8 Category</th><th>Islands Resilience Policy for Island groups fed via subsea cables</th></tr>
<tr><td>Over 60MW and up to 300MW</td><td>D</td><td rowspan="2">Group demand secured for sustained long duration
N-2 condition through a combination of network assets and local generation (including third party).</td></tr>
<tr><td>Over 4MW And up to 60MW</td><td>C</td></tr>
<tr><td>Over 1MW And up to 4MW</td><td>B</td><td rowspan="2">Group demand secured for sustained long duration
N-1 condition through a combination of network assets and local generation (including third party).
N-2 condition managed through use of portable generation or use of existing generation on island if available.</td></tr>
<tr><td><1MW</td><td>A</td></tr>
</table>

Table 7: Summary of Islands Resilience Policy

This standard is technology-neutral (i.e. the resilience could be met by network assets or, third party solutions) recognising that specific instances are unique to each island group and the long-term solution may differ between island groups of similar demand size.

For island groups with demand greater than 4MW we will ensure that they have sufficient capability to maintain supplies for loss of two in-feeding submarine cable circuits. This could be achieved through a third cable circuit or the use of on-island energy sources including third party assets with associated control functionality. Such generation must be capable of securing island demands for a sustained period during all seasons and weather conditions.

For island groups with demand of 4MW or below we would ensure sufficient capacity existed to manage the loss of a single submarine cable circuit. This could be achieved through a second cable circuit or the use of on-island energy sources including third party assets. Again, such generation must be capable of securing island demands for a sustained period and during all seasons and weather conditions. In the unlikely event of the loss of this contingency during a system outage then we would look to mobilise portable generation in advance to restore supplies. This could also be achieved using local island generation if available.

For many island groups there may still be a requirement to operate a network disconnected from the main GB system (i.e. in islanded mode). We would need to have the appropriate control infrastructure in place to achieve this relevant to the specific needs of that island group.

Achieving these future resilience levels is a longer-term ambition for many of our island groups and aligning with our commitment to remove reliance on DEG, we intend to realise this ambition by the end of RIIO-ED3 in 2033.

2.4.1.3. Implications of Load Managed Areas

Load Managed Areas (LMAs) are a legacy arrangement under which SHEPD has been able to manage load in a constrained area by shifting load on domestic storage heaters. The technology underpinning this system is approaching end of life and cannot be replaced as critical parts are no longer manufactured.

SHEPD controls LMAs through the Radio Teleswitch System (RTS) which was introduced to manage the load profile of storage heaters and water heating and has been highly successful not only in diversifying demand but in providing customers with access to cheaper overnight tariffs to charge their storage heaters.

In RIIO-ED2 we have committed to review the application of LMAs in SHEPD's licence area, removing them and replacing through commercial and/or technical solutions depending on the outcomes of cost-benefit analysis. Potential market-based opportunities are currently being developed by a dedicated project team.

2.4.1.4. Community energy projects

We have engaged with stakeholders through both webinars and bilateral meetings to understand the current status of community energy projects on the Outer Hebrides and its future potential.

There are over 23MW of community energy schemes currently operational in the Outer Hebrides, with this being dominated by onshore wind generation. The Inner Hebrides (particularly the islands of Islay and Jura) produce around 5% of its electricity demand from on island based renewables; however, located in a Constraint Managed Zone (CMZ) there are restrictions to import and export.

On Orkney, the community energy sector is represented by Community Power Orkney, which is made up of five community groups: Eday Renewable Energy Ltd, Hoy Energy Ltd, REWIRED Ltd (Rousay, Egilsay & Wyre), Shapinsay Renewables, and Stronsay Renewable Energy Ltd. These five groups, alongside Westray Renewable Energy Ltd, own a total of [redacted] of onshore wind projects comprising six [redacted] turbines. Several wind projects are either wholly or partly locally owned, with the Hammars Hill wind farm comprising five turbines and a combined capacity of [redacted]. This project has the local authority, Orkney Islands Council (OIC), as the main investor and 90% of its total equity is held within Orkney.

OIC is also engaged in constructing three new community wind farms at Quanterness, Hoy and Faray, each comprising six turbines. When constructed, the total capacity of all three wind farms will be almost [redacted] MW.

Such relatively significant volumes show the potential for community energy schemes to help support the future energy needs of the Scottish islands.

From a DSO perspective this could either be in the form of flexibility services to defer the need for network investment or for longer term services to provide energy in the event of a power outage. Key to achieving both these opportunities is the ability to store excess wind generation for use in other time periods. We are interested in the development of hydrogen solutions on the islands and have engaged with the RIPEET project.[39] We will continue to monitor progress to understand how and when such developments could feed into our SDPs.

2.4.1.5. Whisky distillery decarbonisation

Whisky distilleries form a significant part of the demand on many Scottish islands, most notably Islay and Jura, being a key industry and employer on the islands. The heating processes for distillation are significant, and currently utilise carbon sources such as peat. Distilleries are keen to decarbonise and see electrification as a viable way to achieve this. We have worked with the SWA and the Islay Energy

39 About RIPEET | RIPEET Project

Trust to better understand both distilleries' plans for decarbonisation and future investment plans. This included surveying distilleries to gain their insights.

Feedback has generally been that these future plans are uncertain, and many distilleries are actively considering a range of decarbonisation strategies. However, this is in part due to a lack of certainty in future network capacity.

To recognise this uncertainty, we have developed a confidence model on forecasts. This considers two factors for developments that have yet to submit a formal connection application:

- Maturity of the developer: an existing connection looking to increase demand would provide a higher confidence than a prospective new development yet to apply for connection.
- Project certainty: shared and defined plans would score more highly than the absence of firm plans.

These two factors can be represented through a four-box model as shown in Figure 16. A mature development from an existing party would score as a high confidence, whilst a speculative developer with no firm plans would score as low confidence.

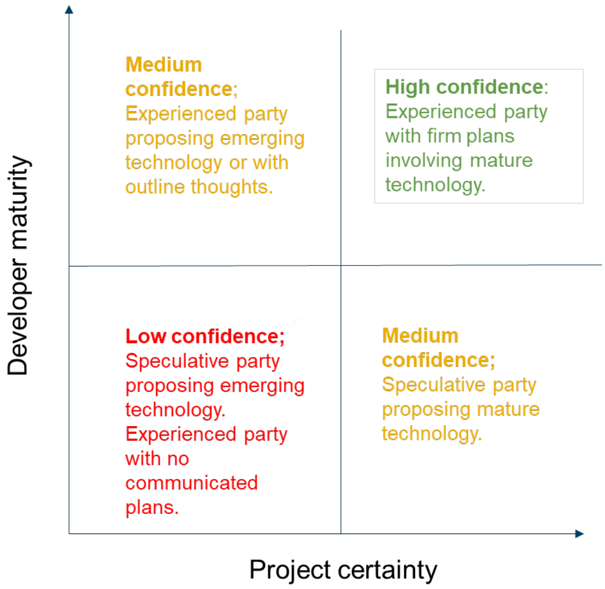

Figure 16: Forecast confidence model

We have interpreted the information gathered as follows:

- High confidence information has been used in our forecasts for demands in RIIO-ED2 and beyond.
- Medium confidence information has been used in our forecasts for demands in RIIO-ED3 and beyond.
- Low confidence data has been used in our longer-term analysis from 2040-2050. We have carried out two sensitivities with this data;
    - 50% of potential low confidence projects decarbonise through electrification by 2050. This is the central scenario used.
    - 100% of potential low confidence projects decarbonise through electrification by 2050.

We will keep these forecasts under review on an annual basis as our SDPs are updated.

2.4.2. Approach to optioneering

Approach to analysis

We have used the insights and forecasts from DFES and Regen's work to produce load forecasts for relevant island groups. Our system analysis has considered two main forecast conditions:

- Winter peak demands with minimal embedded generation
- Summer minimum demands with high levels of embedded generation

We have assumed that the CT DFES is the base scenario but have carried out sensitivities for Leading the Way (LW) scenario and other DFES where appropriate. Whisky distillery demand forecasts have been added where required. Power system analysis is then undertaken to understand the relevant thermal, voltage and fault level needs in the study area.

Approach to option development

We have consciously identified, assessed and selected options through a whole system lens to take account of energy requirements in 2050, as well as the interactions with transmission, embedded generation and potential future energy sources and demands. The solutions put forward in this application have been selected for their ability to form part of a long-term, whole system solution which is an explicit requirement upon SHEPD further to its RIIO-ED2 licence obligations.

The core solutions being proposed as part of this re-opener application include submarine cables and onshore network assets. The submarine cables will have a minimum manufacturer's design life of 25 years, with a view to achieving a 45-year installed asset life with detailed route engineering and cable protection. Onshore assets will look to achieve the anticipated asset life as recorded in the CNAIM V2.1. This means that, subject to unexpected asset failure, these solutions should continue to fulfil their respective roles and not require replacement or further intervention through multiple future price control periods.

A number of options have been considered, some based on specific feedback from island stakeholders. It should be noted that some of these elements are not sufficiently mature today, but potentially form part of our longer-term strategic development. All elements will be further considered in the development of our RIIO-ED3 plans.

1. **Distribution network elements** – We have considered how future network needs could be met with additional distribution investment. It is generally recognised that all islands will need to remain connected to the mainland GB system confirming the need for continued network circuitry and capacity. Capacity requirements will need to meet forecast demand and generation requirements. The need for additional infrastructure to meet future resilience requirements and the use of 66kV infrastructure has also been considered.
2. **Transmission network elements** – We have worked closely with SSEN Transmission to understand their future requirements and how these impact distribution system needs including system resilience. We have also endeavoured to understand future planned transmission works affecting the islands and how they may impact our developments. We have explicitly included transmission options, where appropriate, within our detailed optioneering process. These have also been discussed with SSEN Transmission and are detailed in the individual island group chapters.
3. **Use of third-party solutions** – We have discussed with stakeholders the use of new technologies such as hydrogen and other forms of storage to help resolve some of the drivers for change. Such technologies may be able to provide the longer duration forms of flexibility that we would require to manage system resilience in the unlikely event of a submarine cable failure.

4. **Use of flexibility** – We see flexibility as a potential requirement in all developed options. For load related drivers, it can help optimise the timing of future investment needs and this is where we see a primary use case. Our recent islands flexibility RFI has not highlighted significant volumes of flexibility on the islands today, however we will be considering the future potential in our RIIO-ED3 development work. However, it has triggered a potential stability solution on the Outer Hebrides which could help reduce DEG operations in the period 2027-2030.

Chapters 3 to 7 set out the implementation of our approach for the specific island groups.

The study years have been selected based on the criteria below:

- The need to maintain network compliance within RIIO-ED2 (by 2028).
- Removal of reliance on DEG by 2033.
- GB net zero target for 2050.

2.4.3. Assessing options

Figure 17 shows how we have assessed wider whole system options within our HOWSUM methodology. Transmission and third-party solutions are generally considered in the detailed optioneering stage. We have also considered distribution options at 66kV where appropriate. These options are then tested through the deterministic (Ofgem) CBA to determine the most efficient solution.

Where developments are driven by load related needs, we will follow this up through our DNOA process, where we will consider the use of flexibility as either an alternative to investment or as a tool to defer investment.

Finally, we have used our Strategic CBA to further optimise our solution. This has primarily been used to consider the transition to zero carbon resilience on the islands (e.g. additional circuitry and/or DEG replacement) and hence has no material impact in this application. However, it does provide insight into the current optimum pathway for island developments into the 2030s. The Strategic CBA has been used to:

- Understand the relative costs and benefits of reduction in carbon emissions through earlier intervention.
- The impact of additional network investment on the potential for local/community generation through earlier construction.

The Strategic CBA has been used where there is a possibility for further insight into the different benefits realised through alternative investment options or into the impact of investment timing. Further details on the Strategic CBA can be found in Section 2.3.4.1.

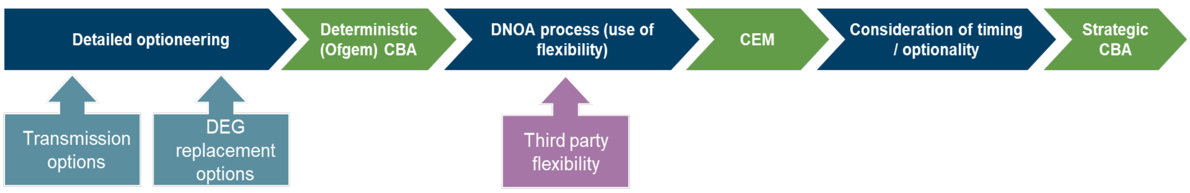

Figure 17: Consideration of whole system options within HOWSUM planning process

2.5. Future work relevant to HOWSUM

As detailed in this submission, we have undertaken significant investigations to understand the future energy needs of the Hebridean and Orkney island groups and their impacts on future networks requirements. However, we recognise the current level of uncertainty, particular in energy needs beyond the next 5-10 years. We will therefore keep our 2050 strategic plans under review through our Strategic Development Planning process. This will enable our plans to be updated as energy forecasts evolve and the level of uncertainty decreases.

The next significant milestone will be the production of a plan for the period 2028-2033 which will form part of our RIIO-ED3 Business Plan submission. A key driver in this period will be the requirement to eliminate carbon and other emissions from our DEG fleet. As mentioned, we will undertake further development work in RIIO-ED2 to understand the readiness of a zero-carbon alternative to DEG including third party alternatives. This would particularly apply to the station on Tiree which initial investigations have suggested that a battery could form part of the optimum solution for Coll and Tiree.

We note that there are two network interventions that we are seeking funding for in this regulatory period, but which have a delivery that is likely to straddle price control periods. We do not believe that regulatory price control periods should stifle the needs and aspirations of Scottish islands and as such we have proposed funding arrangements which mitigate this.

We will also continue to utilise HOWSUM development funding in RIIO-ED2 to develop network options needed in RIIO-ED3. This will ensure a seamless pathway towards RIIO-ED3 with no loss in momentum due to the change in regulatory periods. We have included a request for additional development funding in Section 2.6.6.

2.6. Cost information

This section provides information on how we have derived and used cost data in our analysis. More detail is included in individual island chapters, individual CBA and CEM CBA.

2.6.1. Data sources

For the purposes of the HOWSUM 2025 application, SHEPD has developed a cost book to ensure that a consistent approach to project estimating has been taken for similar assets. This cost book is based upon internal unit rates, Ofgem RIIO-ED2 unit rates and unit rates from our SEPD license area for voltages exceeding 33kV. Assumptions for 66kV submarine cable have been determined based on market engagement and similar costs seen across the wider industry. We emphasise that all cost assumptions are estimates, albeit reflecting on recent actual costs where relevant. The market is subject to change and we are experiencing significant cost volatility in many areas. Indicative costs for these projects will not be clear until procurement activities are underway, and final costs will only be confirmed once projects are fully implemented.

2.6.2. Key cost drivers

2.6.2.1. Submarine

SHEPD is the only DNO in the UK to develop, implement and maintain submarine cable installations at scale, which has specific impacts on the level of cost and risk we carry throughout the lifecycle of these projects.

The cost of delivering submarine cables and offshore projects is driven by many factors outside of SHEPD's control and can vary depending on many factors, much more so than typical onshore projects.

For example, we may require multiple vessels for windows that are difficult to predict due to weather and seabed conditions. Different vessels and equipment are required for geophysical and geotechnical surveys to map the seabed and inform environmental and ground conditions. For installation and protection of the submarine cable a cable lay vessel is required in conjunction with trenching vessel, support vessels, and a boulder clearance vessel. Some of these vessels may be combined depending on contractors but this approach is not always possible.

It is important to note that cable laying vessel requirements are different depending on the site-specific parameters such as depth of water, cable length and weight, exposure to currents, and sea states. This means we require suitable specialist vessels for each project. [redacted] Some specialist vessels may require to be chartered in from distant locations such as South America or Asia which can increase hire costs and mobilisation / demobilisation. We aim programme our works in the most efficient way possible to optimise use of vessels on multiple projects. We are also gradually standardising cable sizing to improve cost efficiency.

Cost estimates for much of these works are not fully known until a cable route design is finalised, including on bottom stability study and cable burial risk assessment. Even at this point, we are finding [redacted] Additional intertidal cable protection and stabilisation is likely to be required for submarine cable landfalls. This activity is very weather sensitive, with much lower weather limits than cable laying activities. This is mainly attributed to the need to have divers in the water conducting the installation. All of these uncertainties are highly specific to our operations and can lead to unpredictable costs.

A further cost consideration as part of this submission will be costs associated with potential type testing activities for 66kV assets. SHEPD do not currently have these assets in our network and as such will require to undertake additional testing and approval prior to their use (see Section 2.6.3).

2.6.2.2. Onshore

Many offshore solutions also require onshore work to connect to the existing distribution network. Onshore substation works will likely represent the highest cost of all onshore elements. In some instances, we may need to construct new substation buildings to house equipment and purchase land for this purpose. Onshore overhead line works are likely to be subject to [redacted]

Costs used in our analysis are based on current SHEPD internal unit rates, which are averages from projects delivered across the whole of the SHEPD network area, and works will be subject to competitive tenders to acquire competitively priced, actual market costs. Where underground cable works are required, [redacted] Until a final route is determined and detailed site investigations are complete, including the use of trial holes, specific ground conditions are unknown. It is likely that specific to our operating areas in the Scottish islands and the remote mainland shores hard rock will be present, which [redacted]

See Section 2.6.3 for further information on cost drivers in the context of cost uncertainty and mitigations.

2.6.2.3. Data from similar projects

We have applied relevant cost data from recent projects which are comparable to those proposed in this application. Table 8 provides examples of similar projects.

Project	Commentary on similarities
[redacted]	

Table 8: Comparable projects used in developing cost estimates

2.6.3. Cost uncertainties and mitigations, including sensitivity analysis

There are a significant number of risks associated with delivering our HOWSUM projects given that operations take place offshore in harsh environmental conditions. Key areas of uncertainty that may have a significant impact on delivery are described below.

- **Weather conditions** can extend the length of time required to survey, install, and protect submarine cables and increase total costs. [redacted] To mitigate the risks associated with weather, we will target the summer months where possible for installation, when the risk of poor weather at its lowest. This strategy however can often be restricted by the contractors' availability, and targeting the summer months may not always be possible. This summer period is when vessels are most in demand and the price of vessel day rates are likely to be higher, but with more certainty on overall costs. [redacted]

- **Fishing compensation** is uncertain and can impact cost and programme duration. [redacted]
- **Submarine cable commercial arrangements** involve a range of uncertain costs. [redacted] arly engagement with the insurance market is required to manage this risk however it may not fully mitigate it. Related aspects are discussed at Section 2.7.1.
- **Submarine cable manufacturing** is experiencing volatile commodity prices, a challenging insurance market and long lead times. The cable supply market is currently very tight, and cable specification needs to comply with SHEPD Design Authority, [redacted]. [redacted] he cost of copper is also volatile due to global market conditions and is a significant component of cable cost risk. Section 2.7.2.1 provides more information on our submarine cable contracting strategy.
- **Onshore works** involve uncertainties in terms of resource, materials, consenting, delivery and associated delays. [redacted] Materials and plant are currently procured in advance to manage uncertainty and manufacturing timescales. Section 2.7.2.2 provides more information on our onshore contracting strategy.

Non-standard assets also represent an area of uncertainty. In this submission, proposed projects will use 66kV rated cables and overhead line. [redacted] SHEPD may also require additional testing, approval and training for the use of these items on the network. The use of this voltage level will also newly require procurement and storage 66kV spares.

[redacted]

2.6.4. Cost efficiency

We have prioritised cost efficiency throughout the HOWSUM process. We see potential for efficiencies in many areas and have discussed these in more detail at Section 2.7 and in the individual island chapters.

2.6.5. CAIs

When setting mechanisms for RIIO-ED2, Ofgem introduced the Indirects Scaler mechanism. This was designed to mechanistically increase allowances to reflect that delivery of LRE mechanisms[40] lead to increased indirect expenditure. The aim of this mechanism was to address some of the uncertainty in the need or level of indirect allowances driven by the inclusion of the LRE uncertainty mechanisms. For HOWSUM, however, this automatic mechanism is not explicitly applied, despite the work activity incurring the same level of additional indirect expenditure above baseline funding as the LRE mechanisms.

Over recent months we have completed significant reforecasting and deliverability studies in line with current network demand forecasts to get a firmer view of the required network investment over the rest of RIIO-ED2 and beyond. As part of this, for some projects that we were minded to submit under the LRE re-opener, we have taken a more holistic view and are now of the view that they apply more appropriately as part of our HOWSUM approach, which is solution focused but cost driver agnostic. The result of this is that the mechanistic uplift from the Indirects Scaler will not automatically apply, where it would have should these projects have been submitted under the LRE Re-opener. We have therefore included additional funding requests within this re-opener window for indirect expenditure driven by HOWSUM. This covers both HOWSUM applications previously submitted and those we are submitting in this January 2025 window.

As no mechanism was recorded as part of the HOWSUM determination, we propose to utilise the same scaling factor that was agreed with Ofgem for the LRE re-opener. The works proposed through HOWSUM are very similar in nature to the LRE programme and therefore we deem it appropriate to utilise the same methodology for CAI recovery. We are therefore seeking to recover additional CAI costs utilising the 10.8% scaling factor as applied to the LRE re-opener. Table 9 sets out these values for the January and July 2024 applications, and Table 10 provides a summary of values for this application. CAI values for this application are confirmed in each island chapter.

CAI costs - January 2024 and July 2024 applications (£m, 2020/21 price base)	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**Total**
January 2024 application	-	-	[redacted]	[redacted]	-	[redacted]
July 2024 application	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Total CAI adjustment - January 2024 and July 2024 applications	**-**	**-**	[redacted]	[redacted]	[redacted]	[redacted]

Table 9: CAI costs associated with January and July 2024 applications

CAI costs - January 2025 application (£m, 2020/21 price base)	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**Total**
Inner Hebrides – Islay-Jura	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Orkney	-	-	-	[redacted]	[redacted]	[redacted]

40 Defined by Ofgem as applicable spend under the Secondary Reinforcement Volume Driver, Low Voltage Services Volume Driver or the Load Related Expenditure Re-opener.

CAI costs - January 2025 application (£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Outer Hebrides and Skye	-	-	[redacted]	-	[redacted]	[redacted]
Inner Hebrides - Mull-Tiree	-	-	-	-	[redacted]	[redacted]
Whole system analysis – all islands	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Total CAI adjustment - January 2025 applications	**-**	**-**	[redacted]	[redacted]	[redacted]	[redacted]

Table 10: CAI costs associated with January 2025 application

We consider that additional output resulting from increased funding under a re-opener should be paired with a commensurate increase in indirect allowances to cover increased overheads. In lieu of a more explicit solution in RIIO-ED2, we welcome the opportunity to engage with Ofgem during upcoming RIIO-ED3 consultations about how best to reflect increased indirect spend driven by uncertainty mechanisms and increased allowances that sit outside of LRE.

2.6.6. Demonstrating additionality - HOWSUM development funding

A baseline allowance of £20.6m for HOWSUM project development funding was allowed by Ofgem in its RIIO-ED2 Final Determinations, recognising that the projects contained within HOWSUM were excluded from baseline allowances, and SHEPD required to progress works ahead of applying for further funding through the mechanism. SHEPD confirmed to Ofgem costs associated with preparatory works for the HOWSUM programme of activities. This allowance is intended to cover the activities in Table 11.

Activity	Detail	Indicative allowance component
Offshore surveys	Route surveys and geophysical samples	£18m
Third-party surveys and samples	Earthing studies, remote utility survey, landfall / peat probing and cable routing surveys, environmental studies, overhead line and onshore route surveys, substation / existing network modification survey	£1m
Engineering and whole system feasibility studies	Feasibility assessment, consenting activities, engineering	£1m

Table 11: HOWSUM Development Funding baseline allowance scope

We have identified through our project cost forecasting activity that further development spend is required within RIIO-ED2 to enable swift delivery of projects identified across RIIO-ED2 and into RIIO-ED3. This is in addition to the allowances provided above. It includes the need to progress the development of some of the medium-term investments required to fulfil the whole system solutions for the island groups which will be delivered across the end of RIIO-ED2 and into RIIO-ED3 as well as some projects identified for execution solely within RIIO-ED3. As such these additional development costs are being sought as part of the funding request in this application. The additional development funding requested in this submission is [redacted]. A summary is set out in Table 6, and detailed in Table 12.

Given the nature of project development and parallel activity timelines, we cannot define at which time and on which specific project the current development funding will run out. Therefore in Table 6 we have forecast the utilisation of development funding by projects in sequential order.

(£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
HOWSUM Development Funding baseline allowance[1]						**20.63**
Development funding committed to date[2]	[redacted]	[redacted]	[redacted]	0.00	0.00	[redacted]
Adjustment request:						
ISLAY - JURA						
Carradale – Port Ellen 1 & 2[3]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Total development costs[4]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development cost (pre-funded)[5]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development funding adjustment[6]	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Port Ann – Knocklearach[3]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Total development costs[4]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development cost (pre-funded)[5]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development funding adjustment[6]	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
ORKNEY						
Thurso – South Ronaldsay[3]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Total development costs[4]	0.00	0.00	0.00	[redacted]	[redacted]	[redacted]
Development cost (pre-funded)[5]	0.00	0.00	0.00	[redacted]	[redacted]	[redacted]
Development funding adjustment[6]	**0.00**	**0.00**	**0.00**	**0.00**	[redacted]	[redacted]
OUTER HEBRIDES						
Skye – Harris 2[3]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Total development costs[4]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development cost (pre-funded)[5]	0.00	0.00	0.00	0.00	0.00	**0.00**
Development funding adjustment[6]	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
MULL, COLL AND TIREE						
Mainland – Kerrera – Mull[3]	0.00	0.00	0.00	0.00	[redacted]	[redacted]
Total development costs[4]	0.00	0.00	0.00	0.00	[redacted]	[redacted]
Development cost (pre-funded)[5]	0.00	0.00	0.00	0.00	0.00	**0.00**
Development funding adjustment[6]	**0.00**	**0.00**	**0.00**	**0.00**	[redacted]	[redacted]
HOWSUM whole system analysis and DEG evaluation	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Total development costs[4]	0.00	0.00	[redacted]	[redacted]	[redacted]	[redacted]
Development cost (pre-funded)[5]	0.00	0.00	0.00	0.00	0.00	**0.00**

(£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Development funding adjustment[6]	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	[redacted]
Total development costs adjustment	**0.00**	**0.00**	[redacted]	[redacted]	[redacted]	**7.89**

1. This is the original RIIO-ED2 HOWSUM development funding baseline allowance of £20.6m.
2. The development funding committed to date are the development costs associated with the interventions included in our January and July 2024 applications. The remaining amount is available to utilise on interventions in our January 2025 application.
3. Project costs including development costs, before the addition of risk and CAI costs.
4. Total development costs for the project.
5. The amount of development costs which has been covered by the existing HOWSUM development funding baseline allowance of £20.6m. Within our cost analysis this has been applied to reduce the funding request for development costs for each island group up to the point at which it is fully utilised. Any additional development costs beyond this allowance are set out at 'Development costs (request)' and have been included in our funding request.
6. This is the amount of additional development funding required to progress the relevant island interventions, after the HOWSUM development funding baseline allowance has been applied.

Table 12: HOWSUM development costs allowance adjustment summary

Within the additional [redacted] we have requested, some of this relates to activities which require to be undertaken in RIIO-ED2 for the delivery of identified RIIO-ED3 projects (Mainland – Mull, Skye – Harris 2, Port Ann – Knocklearach and strategic whole system analysis and DEG evaluations). Should this portion of funding not be approved SHEPD cannot progress the development of these works until the start of RIIO-ED3 in 2028, provided that funding is confirmed at that stage. This is likely to push activities to the end of RIIO-ED3 or beyond and put network security at risk, as well as risking sections of the network becoming overloaded due to delays in the network upgrades. This could also result in increasing DEG emissions.

2.7. Deliverability and risk

There are several complexities associated with submarine cable projects which require consideration in the context of the procurement strategy and process, and project delivery. [redacted]

2.7.1. Procurement and delivery challenges

There are a number of challenges associated with procurement and delivery for submarine cable projects. [redacted] and work closely with Ofgem to ensure that the correct solution and associated funding is available.

Considering specific challenges in turn:

- *Location*:
  - The Scottish islands have various logistical challenges due to their remote location including but not limited to accessibility, additional delivery charges, longer transport times, small local supply chain, marine/environmental/ecological challenges, and variable and uncertain weather conditions due to proximity to the sea / ocean.
  - Site specific challenges will dictate the equipment and more specifically the vessels which are required to conduct the cable install. Not all vessels can be utilised in all locations.
- *Market conditions*:
  - [redacted]
    - [redacted].
    - Ukraine and other global tensions – impact on global supply chain / price increases / scarcity of materials.
    - [redacted]
    - High demand for raw materials.
    - SHEPD projects require insurance to support their development and associated construction. [redacted]
- *Supply chain:*
  - [redacted]
  - Capacity / capability of cable manufacturers – any submarine cable used must have SHEPD Technical Authority approval and no factory joints. The Technical Authority specifies the requirements of any cable which is to be connected to the SHEPD network. In this instance the requirement is that the cable is type tested which involves an electrical and mechanical test of the fully manufactured cable. A type test certificate can be applied to cables of the same design with a smaller cross-sectional area but not larger. [redacted] SHEPD now specify that our cables should have no planned factory joints and be made in one continuous length. [redacted]

2.7.2. Procurement and delivery approach

2.7.2.1. Procurement and commercial strategy – submarine cables

The section highlights the general contracting approach undertaken by SHEPD for submarine cable procurement, reflecting on the challenges noted in Section 2.7.1.

It should be noted that SHEPD is required to comply with the Utilities Contract (Scotland) Regulations 2016 and as such regulated tender processes shall be followed where relevant.

The supply chain required to deliver these projects has been tested through delivery of RIIO-ED1 projects [redacted]

[redacted]

- [redacted]
- [redacted]

[redacted] using the HOWSUM development funding baseline allowance.

2.7.2.2. Procurement and commercial strategy - onshore

[redacted]

[redacted]

Frameworks are already in place for procurement of long lead items. Materials and plant are procured in advance to secure availability due to uncertainty and manufacturing timescales.

2.7.2.3. Project delivery and monitoring

This section sets out information on project delivery and monitoring common to all projects. Project-specific detail is included in the individual island group chapters.

Project delivery approach, management and monitoring

Projects will be managed under SSE's Large Capital Project (LCP) governance framework or the Distribution Governance Investment Framework depending on the value of the project. These governance frameworks ensure that all capital investment projects for the SSE Group are governed, developed, approved and executed in a safe, consistent, sustainable and effective manner.

Delivery of the projects will be led by Project Managers who will manage project teams made up of key disciplines such as Engineering, Consents, Procurement & Commercial, Safety, Environmental and Planning. This project teams will be supported by other disciplines such as Quality, Operational Personnel, Risk Management, and others as required.

Dedicated Project Planners will set the project baseline programme at the beginning of the project and monitor progress throughout. Progress will be informed by the project team and by Contractors who will submit their programmes to the project planner regularly identifying any delays and changes.

To manage cost there will be procurement, insurance and legal reviews held at all relevant stages of the projects. This will define the contract strategy and ensure that SHEPD will work in current market conditions to negotiate contracts which protect SHEPD and our customers as well as managing risks appropriately. Costs will be estimated at each stage of the project and will include tendered costs as the project progresses to achieve accurate estimates. Regular review of expenditure and forecast will be done throughout the project to monitor this and deliver the project within budget.

Risk will be managed in accordance with the relevant governance framework to ensure risks are identified, assessed, mitigated, and monitored. This is done using a risk management system that the project team uses to capture this process and to review the risks regularly. The risk cost will be determined using Quantitative Cost Risk Analysis to provide a realistic appraisal of the potential value.

Change is managed through the change control process which ensures that change is evaluated, reviewed and approved at the proper authority level. This prevents changes from the approved project objectives and ensures that the consequences of the change and their impact on the project are identified, understood and managed.

2.7.2.4. Project delivery and allowances

As we have mentioned in this section, there is significant risk out with our control around the timing of delivery for many areas of this programme. While we are fully committed to risk mitigation where possible to enable delivery within the timeframes we have specified, some risks will remain and may come to fruition. We would therefore like Ofgem to confirm that allowances will not be lost in a scenario where, due to timing of potential risks, delivery of works is not complete within RIIO-ED2, or original phasing of works across RIIO-ED2 and RIIO-ED3 changes, and that a mechanism is in place to ensure allowance continuity. Our view is that transitioning from one price control period to the next should not impact our ability to deliver these works, especially as the aim of this re-opener application is to take forward optimum long-term solutions to network planning.

2.7.3. Resources

The internal resource provided by SHEPD to manage each project is detailed in Section 2.7.2.3. The required team members and disciplines for each project will be used across multiple projects where capacity allows. This will be determined by a resource plan to ensure that resource is allocated in accordance with the available capacity and effort required. Where resources are not available due to the increased volume of work, SHEPD may recruit or use external temporary resource to resource peak times of activity.

The projects will be delivered and constructed by contractors who will be required to evidence at the procurement stage that they will resource the project appropriately to deliver in a timely and safe manner.

For each project an Execution Resource Review will be carried out that finalises the project structures and teams, ensuring that all key roles are resourced, including the appointment of Suitably Qualified and Experienced Personnel or Site Supervision and Quality intervention roles.

2.7.4. Mitigation measures

Refer to Section 2.7.7 which includes details on mitigation measures to reduce risk. Project-specific mitigations are set out where relevant in the specific island chapters.

2.7.4.1. Governance arrangements

Delivery governance forums are established that are used to manage delivery performance and to provide assurance to key external stakeholders. Any agreed mitigation measures that can be taken to address deviation from the project delivery plan are decided within this project delivery governance that comprises of:

- Programme Performance Review (monthly with follow up on key issues after two weeks, if required): forum to review a 'by exception' summary of project delivery performance, key risks and to identify decisions or issues for escalation.
- Portfolio Performance Review (monthly): forum to review in-month performance, escalated project delivery issues, near term planning lookahead, successes and lessons learned in month and resources and supply-chain planning.
- Large Capital Delivery (LCD) Performance Review (monthly): forum to review in-month and in-year performance, Large Capital Project Committee (LCPC) project performance and report readiness, near term planning look-ahead, escalated programme issues, successes and lessons learned and resources and supply-chain planning.
- Large Capital Project Committee (monthly): reporting to provide a summary of LCPC Project delivery performance.
- Materials Review Group (monthly): Forum to discuss current lead-time schedule considerations for projects including long lead items and to inform procurement of changes to pipeline of materials required as projects exit the design stage.
- Risk Review Group (monthly): forum to discuss risk exposure for projects, covering escalation and drawdown, including to / from programme and portfolio levels.
- Change Assurance Panel (fortnightly): forum to review and validate the accuracy and quality of the change information within submitted Baseline Change Control Forms. They will also provide assurance of the proposed cost, schedule, and risk impact assessment.

2.7.5. Reporting mechanisms

Reviewed within the governance forums, performance metrics measure the activity and overall performance of how work is delivered. These core performance metrics represent a minimum set necessary to adequately assess delivery performance and comprise of cost, schedule, risk, and change. Status reporting is an indicator of a project's position in relation to its ability to deliver its objectives for example in respect of time, cost and quality. Clear, concise, and consistent report narrative is important at all levels so that key stakeholders can resolve escalated issues and understand the drivers of performance trends.

2.7.6. Areas of ongoing uncertainty

2.7.6.1. Procurement, commercial and delivery risk

In the context of the challenges set out in Section 2.7.1, there are a significant number of risks associated with delivering large capital projects, particularly where operations take place offshore in harsh environmental conditions. General areas of uncertainty include the following:

- [redacted]
- [redacted]
- [redacted]
- [redacted]

Weather for submarine cable survey and operations can extend the length of time required to survey, install, and protect the submarine cables as well as increasing costs. [redacted] To mitigate the risks associated with extending the programme, SHEPD will target the summer months where possible. Targeting the summer months does depend on vessel availability from contractors which is a risk considering the oversubscribed market. [redacted]

Fishing is an area of uncertainty on submarine cable projects and can impact cost and the programme duration. [redacted]

Where cable supply will be required there is uncertainty relating to commodity prices, [redacted] The cost of copper is an uncertainty and changes in the global copper market can influence cost both up and down. This will be mitigated [redacted]

2.7.6.2. Managing uncertainty in future island needs

Our DFES forecasts, complemented by specific sector analysis, provides a best view of the future energy needs of Scottish islands. However, we recognise that the future is not certain, particularly in longer timescales. We manage this uncertainty through a number of mechanisms:

- Consideration of multiple DFES: Our analysis is tested against other DFES and we have adopted a similar approach for distillery forecasts. The Strategic CBA also allows us to test our solutions against different DFES to ensure we have a least worst regrets proposal.
- Staged approach to delivery: We are only seeking funding for components that are needed in the short term. This allows our longer-term plans to be 'living' and change as our forecasts evolve.
- Consideration of diverging pathways: Given the multiple drivers for our work, we are mindful that, in some cases, there may be diverging pathways with longer term projections. We will adopt short term solutions that maintain future optionality wherever possible.

2.7.7. Managing risk

SHEPD has assessed, and proposes to manage, delivery and cost risks in the following ways.

2.7.7.1. Standard project risk

Where project risks are relatively well-understood, and SHEPD has experience of managing those risks, we defined and requested standard risk allowances for each of the projects. The types of risk this will typically cover are [redacted]. We have experience in quantifying the impact of these risks, can be confident that our estimated risk allowances are representative of the likely scale of cost risk involved, and therefore that this is a fair approach for both SHEPD and customers.

The approach we have taken to define these risks is to identify each of the risks we anticipate being relevant for a given project, and to assign a deterministic value for each of these. At this stage of the project, we have assumed the maximum likely incurred costs of these risks, which are summed to give the overall standard project risk value.

We have included a risk register and defined standard risk allowance value in each island chapter where appropriate.

2.7.7.2. Extraordinary project risk

Under recent procurement processes [redacted] SHEPD has a unique exposure through its submarine cable activities and responsibilities.

In our Skye-South Uist application, we set out our view that [redacted]

[redacted] In its Draft Determination for Skye – South Uist[41] [redacted]

In light of Ofgem's current position, we have instead included in this application specific further [redacted]

We have taken this approach because, in the absence of the requested cost adjustment mechanism, we are exposed to material additional costs without any alternative arrangements. We continue to believe that an adjustment mechanism, as has recently been approved for transmission licensees for the same types of cost risk, is better for all stakeholders involved. We don't agree that the TIM is the correct mechanism to manage risk of cost change for items which are identified but which cannot reasonably be quantified or controlled and could have a material impact on project costs. We will engage with Ofgem again on this area [redacted] in relation to this application, and in preparatory workstreams for RIIO-ED3.

41 RIIO-2 Re-opener: Scottish and Southern Electricity Network's 2024 Skye-Uist Project | Ofgem

3. INNER HEBRIDES: ISLAY AND JURA

Our analysis of the Islay - Jura group demand and generation requirements out to 2050 indicates that the existing network infrastructure needs to be supplemented with additional circuits. This includes requirements to meet our Islands Resilience Policy and remove reliance on Bowmore Power Station by 2033.

Our 2050 SDP[42] identifies the requirement for an additional four 33kV circuits supplying the island group of Islay and Jura. Full works are summarised as:

- Two new 33kV circuits connecting Islay to Carradale GSP. These are required by 2028.
- Additional 33kV circuits between Port Ann GSP and Knocklearach on Jura, and between Jura and Islay. These are required by 2033.
- Reconductoring of existing Lochgilphead – Knocklearach and Bowmore – Knocklearach 33kV circuits by 2040.
- A 33kV auto-close scheme at Port Ellen required in RIIO-ED3.

We also seek additional development funding as part of this application to progress early-stage activities, as well as funding to cover risk and CAIs. Table 13 summarises our adjustment request for Islay and Jura, with more detail provided at Section 3.1.

Adjustment summary (£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Total adjustment for Inner Hebrides: Islay-Jura	-	-	[redacted]	[redacted]	[redacted]	[redacted]

Table 13: Inner Hebrides: Islay - Jura allowance adjustment summary

The detailed proposals and justification for the Inner Hebrides: Islay-Jura interventions are set out Appendix 3A - Inner Hebrides: Islay-Jura EJP, Appendix 3B – Inner Hebrides: Islay-Jura Deterministic CBA and Appendix 3C – Inner Hebrides: Islay-Jura CEM CBA. The following sections cross-reference and summarise these documents.

3.1. Allowance adjustment

Table 14 sets out the allowance adjustment sought for Inner Hebrides: Islay - Jura in this submission.

Adjustment summary (£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Total Inner Hebrides Islay-Jura forecast[1]	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Delivery costs[2]	-	-	-	[redacted]	[redacted]	[redacted]
Development costs (pre-funded)[3]	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Development costs (request)[4]	-	-	-	-	-	-
Standard risk allowance[5]	-	-	[redacted]	[redacted]	[redacted]	[redacted]

42 Survey Details | Port Ann and Carradale Grid Supply Points Strategic Development Plan Consultation

Adjustment summary (£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Extraordinary risk allowance[6]	-	-	-	[redacted]	[redacted]	[redacted]
CAIs[7]	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Total adjustment[8]	**-**	**-**	[redacted]	[redacted]	[redacted]	[redacted]

1. 'Total forecast' means all project costs (including development costs, capital and operating costs, risk and CAIs) before the deduction of any applicable HOWSUM development funding baseline allowance.
2. 'Delivery costs' are project costs before the addition of development, risk and CAI costs. These are estimated costs provided prior to carrying detailed procurement and delivery assessment processes. See Appendices 3A to 3C for detail.
3. 'Development costs (pre-funded)' is the amount of development costs which has been covered by the existing HOWSUM development funding baseline allowance of £20.6m. See Section 2.6.6.
4. 'Development costs (request)' is the amount of additional development funding required to progress the relevant island interventions, which the HOWSUM development funding baseline allowance does not cover.
5. The standard risk allowance covers foreseeable and fairly well understood types of risks. See Section 2.7.7 and our risk registers for more detail.
6. The extraordinary risk allowance covers [redacted]s. It has been applied as [redacted] of 'delivery costs', after addition of CAIs. See Section 2.7.7.
7. CAI costs are calculated as 10.8% of total project costs, after addition of project risk allowances. See Section 2.6.5.
8. Total adjustment = (Total Inner Hebrides Islay-Jura forecast – Development costs (pre-funded))

Table 14: Inner Hebrides: Islay - Jura allowance adjustment

3.2. Background to investment

Currently the Isle of Jura is fed by [redacted]

As part of our strategic planning process, an SDP has been developed for Port Ann and Carradale GSPs.[43] This has identified investment needs to secure the network supported by these two GSPs out to 2050. Continuing the analysis initiated in the SDP, we have identified options to address the constraints affecting the network supplying Islay and Jura and have defined a funding request for the specific interventions required in RIIO-ED2.

3.3. Needs case and optioneering

3.3.1. Primary and secondary investment drivers

The primary investment driver for completing this work is increased demand based on our 2023 DFES projections. We have also completed extensive stakeholder engagement with whisky distilleries on the islands to identify their future demand projections. Our analysis projects demand of [redacted] MW by 2050 and confirms that intervention will be required by 2028 to enable the Islay - Jura network to support this demand growth.

43 Survey Details | Port Ann and Carradale Grid Supply Points Strategic Development Plan Consultation

There are also a number of secondary drivers for our proposals. Whilst these are longer term drivers, we have taken them into account both in the development of our longer-term strategy and also in the sizing of cables and other circuit elements within this application. These are:

1. Future generation requirements on the islands: We have investigated the future generation background, ensuring cable sizing will allow the forecast import and export of power to the islands.
2. Future resilience needs of the islands and decarbonisation of DEG: Currently Bowmore Power Station provides back-up supplies for the islands, [redacted]. However, these generators are aging and are a significant source of emissions. We have also reviewed the network in line with our DEG strategy and Islands Resilience Policy. This review indicates that further interventions will be required to allow removal of reliance on DEG and maintain resilient supplies to our customers.

In addition to these drivers there are a number of other factors we have taken into account including the potential use of flexibility to defer traditional reinforcement, and the impact of possible SSEN Transmission works.

Further background information is included in the Port Ann and Carradale Grid Supply Points SDP[44] and Appendix 3A – Inner Hebrides: Islay-Jura EJP.

3.3.2. Methodology for assessing options and for selection of the preferred option

Consistent with both our SDPM and the requirements of HOWSUM described in Sections 2.3 and 2.4 we have undertaken a broad perspective on the future needs for the islands, ensuring we take a whole system view. The following sections detail how we have assessed and selected our preferred option.

3.3.2.1. Whole system opportunities

We have consciously identified, assessed and selected options through a whole system lens to take account of energy requirements in 2050, as well as the interactions with Transmission, embedded generation and potential future energy sources and demands. The solutions recommended under this application are selected on the basis of their ability to form part of a long-term, whole system solution for the Inner Hebridean island group of Islay and Jura.

3.3.2.2. Flexibility opportunities

In August 2024, we launched an RFI to identify new flexibility service participants in a selection of island communities and establish routes to market in this geographical location. The consultation revealed several contractors willing to provide flexibility but they expressed limitations in doing so, including high costs, infrastructure delays, customer engagement barriers, and connection contracts. While there are two potential flexibility service providers we are actively engaging with, most respondents are not yet able to participate. We will continue to engage with these respondents in the hope of flexibility service provision in the future. Again, flexibility solutions will likely require relatively long-term, guaranteed income and support on infrastructure investments to overcome these challenges and expand renewable integration across the islands.

44 Survey Details | Port Ann and Carradale Grid Supply Points Strategic Development Plan Consultation

3.3.2.3. Interactions with transmission works

It is critical to ensure that a whole system view is taken of the future requirements for this area. We have engaged with SSEN Transmission to understand future planned transmission works and how they may impact our developments. We have also considered transmission options as part of our own optioneering within the range of potential outcomes for this island group.

Port Ann GSP forms part of SSEN Transmission's Argyll and Kintyre 275kV Strategy.[45] There has been a significant increase in transmission connection applications from generators in Argyll and Kintyre, predominantly in renewable generation supporting the drive towards net zero.

There is minimal interaction between SSEN Transmission's proposed works in the area and our proposals for the Islay - Jura archipelago. As noted, we have however considered transmission options within our own optioneering.

3.3.3. Options considered

We developed 13 options that could form the basis of a 2050 strategic plan, including a 'do nothing' counterfactual. The options considered are summarised in Table 15.

Option name	Summary
Option 1	• Do Nothing - Do nothing; not compliant with future demand or generation requirements.
Option 2	• Install 3 new 33kV circuits to Islay (one from BAT Wind I substation and one from BAT Wind III substation and one from Port Ann GSP) and 2nd Islay – Jura submarine cable
Option 3	• Install 2 new 33kV circuits to Islay (one from BAT Wind I substation and one from Port Ann GSP), 1 new 132kV circuit from Crossaig to Islay, and 2nd Islay – Jura submarine cable
Option 4	• Install 2 new 33kV circuits (one from BAT Wind I substation and one from Port Ann GSP), 1 new 66kV circuit from Crossaig to Islay, and 2nd Islay – Jura submarine cable
Option 5	• Install 1 new 33kV circuit from BAT Wind I substation to Islay and 2 new 66kV circuits from Crossaig to Islay
Option 6	• Install 3 new 33kV circuits to Islay (one from BAT Wind I substation and one from BAT Wind III substation and one from Port Ann GSP via a longer submarine cable) and upgrade Lochgilphead – Islay North – Knocklearach and Bowmore – Knocklearach circuits
Option 7	• Install 3 new 33kV circuits to Islay (one from BAT Wind I substation, one from new Carradale 33kV GSP and one from Port Ann GSP) and 2nd Islay – Jura submarine cable
Option 8	• Install 2 new 33kV circuits to Islay (one from Port Ann, one from BAT Wind I substation) and 1 new 132kV circuit to Islay (from Carradale 132kV) and install 2nd Islay – Jura submarine cable
Option 9	• Install 2 new 33kV circuits to Islay (one from Port Ann, one from BAT Wind I substation) and 1 new 66kV circuit to Islay (from new Carradale 132/66kV) and install 2nd Jura – Islay submarine cable
Option 10	• Install 2 new 33kV circuits (one from Port Ann, one from BAT Wind I substation) and 1 new 132kV (from Crossaig 132kV) circuits to Islay and install 2nd Jura - Islay
Option 11	• Install 2 new 33kV (one from Port Ann, one from BAT Wind I substation) and 1 new 66kV (from new Crossaig 132/66kV) circuits to Islay and install 2nd Jura – Islay

45 Argyll and Kintyre 275kV Strategy - SSEN Transmission

Option name	Summary
Option 12	• Install 2 new 33kV circuit to Islay (one from BAT Wind I substation, one from Carradale 33kV GSP) and 1 new 66kV circuit to Islay (from Crossaig 132kV)
Option 13	• Install 2 new 33kV circuits to Islay (one from BAT Wind I substation and one from new Crossaig 132/33kV) and 2nd Islay – Jura submarine cable

Table 15: Options considered for Inner Hebrides: Islay - Jura

We reduced the list of options above using power system analysis to simulate the technical operation of each option on the network, resulting in four options that are technically feasible, cost effective and deliverable. More detail on the options is included in Appendix 3A – Inner Hebrides: Islay - Jura EJP. The results of the CBA for the four options are discussed in more detail in Section 3.4.

3.4. Cost benefit analysis and engineering justifications

3.4.1. Summary of cost benefit analysis

We undertook a deterministic CBA for each of the four shortlisted options. This is provided at Appendix 3B – Inner Hebrides: Islay – Jura Deterministic CBA. The CEM tool has also been used to understand the relative benefits of flexibility in both RIIO-ED2 and RIIO-ED3 and is provided at Appendix 3C – Inner Hebrides: Islay - Jura CEM CBA. A summary of the conclusions is provided in the following sections.

3.4.1.1. Cost and other key assumptions

We set out general information on our assumptions and data sources in Section 2.6. The cost estimates presented for the Islay-Jura interventions use the specific assumptions detailed in Table 16. More detail on our cost assumptions is included in the accompanying Appendices 3A, 3B and 3C.

As set out in Section 2.6 SHEPD has developed a cost book in the preparation of our options analysis to ensure a consistent approach to project estimating has been taken for similar assets. This cost book is based on internal SHEPD unit rates, Ofgem RIIO-ED2 unit rates, outturn costs for comparable projects, and unit rates from our SEPD licence area for voltages exceeding 33kV.

Cost / assumption type	Assumptions	Justification and explanation
Submarine cable	[redacted]	[redacted]
Onshore 33kV network	Actual recent 33kV costs.	Utilised to ensure most accurate efficient costs are developed for project estimates.
OHL opex	Actual recent OHL inspection and maintenance costs.	Utilised to ensure most accurate efficient costs are developed for project estimates.
Flexibility opex	Flexibility unit cost and flexibility volume.	Standard flexibility prices based on existing contract data.
DEG running costs	Actual DEG generation running durations and costs.	Based on recent outturn costs.

Cost / assumption type	Assumptions	Justification and explanation
Loss reduction benefit	SSEN internal loss calculator is used to determine the loss reduction benefit through different intervention types.	This approach ensures a common approach through all CBAs. The losses within the CBA include a standard calculation to monetise these reduced losses, along with the subsequent CO2 impact.
Customer Interruption (CI) and Customer Minutes Lost (CML) data	Actual SHEPD data.	The CBA tool utilises this data to calculate the benefit of avoided CIs and CMLs on the network after reinforcement.

Table 16: Islay - Jura core cost assumptions

3.4.1.2. Islay - Jura 2050 strategic plan option costs

The total costs for the four shortlisted options are shown in Table 17. These costs are based on a combination of SHEPD internal unit rates (C1) and assumed submarine cable unit rates [redacted] The costs also include expected substation reinforcement works to facilitate the installation of the proposed submarine cable routes. It should also be noted that CBA costs included here are for the delivery of all elements of the 2050 vision associated with that option, not just the costs within RIIO-ED2. Option 2 can be seen to be the least cost option.

Option	Description	Total (£m)
Option 2	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 2nd Islay – Jura submarine cable	[redacted]
Option 3	Install 2 new 33kV circuits to Islay (one from BAT Wind I and one from Port Ann GSP), 1 new 132kV circuit from Crossaig to Islay, and 2nd Islay – Jura submarine cable	[redacted]
Option 4	Install 2 new 33kV circuits (one from BAT Wind I and one from Port Ann GSP), 1 new 66kV circuit from Crossaig to Islay, and 2nd Islay – Jura submarine cable	[redacted]
Option 13	Install 2 new 33kV circuits to Islay (one from BAT Wind I and one from new Crossaig 132/33kV) and 2nd Islay – Jura submarine cable	[redacted]

Table 17: Inner Hebrides: Islay - Jura option summary costs (£m, 2020/21 prices)

3.4.1.3. Islay - Jura 2050 strategic plan deterministic CBA comparisons

The deterministic CBA results for the four technically feasible options are summarised in Table 18.

Option	10 years	20 years	30 years	45 years	Whole life (55 years)
Option 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Option 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Option 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Option 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 18: Deterministic CBA results for Islay – Jura - NPV at different intervals (£m, 2020/21 prices)

Table 18 shows that the option with the best NPV under the deterministic CBA is Option 2.

3.4.1.4. Application of Common Evaluation Methodology

The CEM tool has been used to identify whether flexibility could be a more efficient method to release capacity in this area of the network.

The islands of Islay and Jura have recently experienced a sharp increase in large connection applications which include several non-domestic loads, such as new and existing distilleries, as well as several domestic loads. The total capacity of the contracted jobs yet to connect is approximately [redacted] MW. Supplying this large additional load will further constrain the network supplying these islands. Also, the [redacted] network capacity is dependent on operating Bowmore Power Station with associated operational and emissions costs. Taking account of the level of flexibility required and the costs and benefits of running Bowmore Power Station, the flexibility NPV calculation does not recommend deferring any proposed network reinforcements.

3.4.1.5. Islay - Jura CBA conclusions

Option 2 is demonstrated to have the lowest option cost and the best NPV, and our CEM assessment does not recommend the use of flexibility to defer investment. Option 2 is therefore our proposed solution. This approach is discussed further in Section 3.5 and the following sections. Please also refer to Appendices 3A to 3C for further details and context.

3.5. Preferred option

This section summarises our preferred option. More information is set out in the Inner Hebrides: Islay - Jura EJP and CBAs at Appendices 3A to 3C.

3.5.1. Description of key features

The preferred option, Option 2, involves installing two new 33kV circuits from Carradale GSP to Port Ellen on Islay by 2028. This would be followed in RIIO-ED3 by installation of a new Port Ann – Knocklearach 33kV circuit and a second Islay – Jura 33kV circuit. We would also install a 33kV auto-close scheme at Port Ellen in RIIO-ED3. Reconductoring of the existing Lochgilphead – Knocklearach and Bowmore – Knocklearach 33kV circuits is also required by 2040. The preferred option is shown below in Figure 18.

The first 33kV circuit from the Carradale GSP network will start off from BAT Wind I 33kV substation and will require underground cables, overhead lines and submarine cable route to reach Port Ellen 33kV substation on Islay. The second circuit will start from Carradale GSP (BAT Wind III 33kV substation) comprising overhead lines and submarine cable route to reach Port Ellen 33kV substation on Islay.

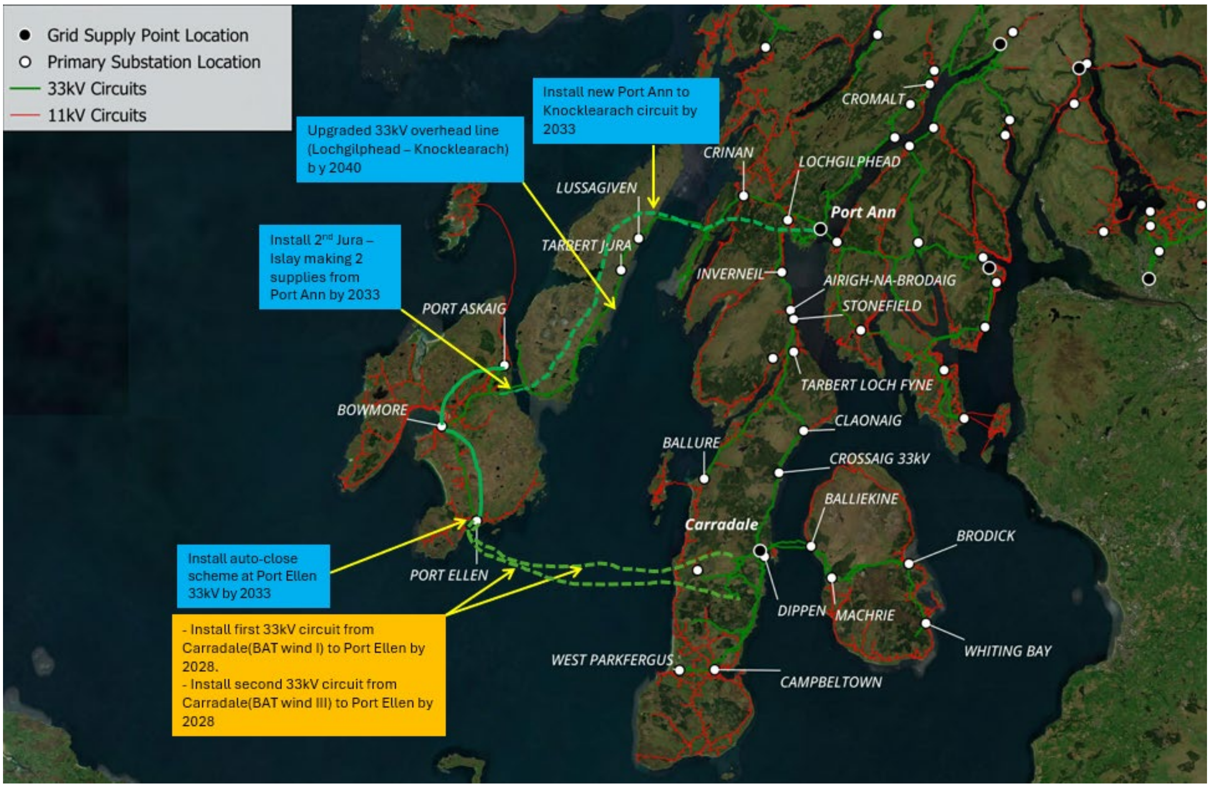

Figure 18: 2050 strategic plan for Islay – Jura (Option 2)

3.5.2. Expected outputs

Table 19 details key expected outputs associated with our recommended interventions.

Project element	Key outputs	Forecast delivery dates[1]
BAT Wind I – Port Ellen	New 33kV circuit from BAT Wind I substation to Port Ellen primary substation	2027/28
BAT Wind III – Port Ellen	New 33kV circuit from BAT Wind III substation to Port Ellen primary substation	2027/28
Port Ellen Auto-changeover	Auto-Changeover scheme at Port Ellen Primary	2027/28
Port Ann – Knocklearach 2	Second 33kV circuit from Port Ann GSP - Knocklearach	2032/33
Islay – Jura 2	Second circuit between Islay and Jura	2032/33
Lochgilphead - Jura 33kV OHL Reinforcement	Reconductor existing Jura 33kV radial OHL	2039/40

[1] Delivery dates are estimated, not wholly within our control and will be refined as projects are further developed.

Table 19: Expected key outputs and years of delivery for Inner Hebrides: Islay – Jura interventions

3.5.3. Timing of investment and rationale for phasing interventions

Due to the inherent uncertainty in predicting the demand and generation profiles of the Islay - Jura archipelago in the future, we intend to implement a staged approach to delivery of the preferred option. We propose to install two new 33kV circuits from Carradale GSP to Port Ellen Primary within RIIO-ED2, for which we seek funding in this application. All other elements of the preferred solution will remain under review as part of our enduring strategic planning process. Our long-term plan has been developed consistently with our broader approach to strategic investment requirements. This process is described in more detail in sections 2.3 and 2.4. Further to our current analysis, our long-term strategy will be most optimally delivered through three main elements:

1. **Immediate requirements that need progressed in RIIO-ED2:**
    a. Near-term least regrets options that resolve immediate drivers and risks, whilst delivering solutions that form part of the least regrets solutions for 2050. This includes our proposal to progress two new 33kV circuits from Carradale GSP to Port Ellen Primary. [redacted], whilst sizing the cable to meet future demands. These components are integral to most feasible options developed and facilitate optionality for future works. Delivery of both circuits together allows synergies and potential cost efficiencies.
2. **Longer term whole system requirements:**
    a. Capacity increase to the Islay - Jura archipelago: There is a need to increase the capacity of the network to Islay - Jura to meet future demand requirements. This could be through augmenting the existing submarine cables or replacing with larger 33kV cables. Island storage will be assessed as an alternative along with flexibility as alternative solutions.
    b. Long term resilience for the Islay - Jura archipelago: Additional distribution circuitry between the mainland and Islay - Jura will help deliver longer term resilience to the island. This will remove our reliance on our DEG fleet by 2033 whilst also allowing other third-party options including hydrogen storage to further develop.

SHEPD has reviewed the timing of investments required as part of the whole system solution for Islay and Jura in order to optimise efficiencies. Originally our network analysis looked at delivering the northern Port Ann – Port Askaig solution by the end of RIIO-ED2 alongside Carradale – Port Ellen 1. The Carradale – Port Ellen 2 solution would be delivered by the end of RIIO-ED3. Following high level route engineering and deliverability assessments, we undertook analysis to see if it was possible to switch the delivery time of Port Ann – Port Askaig and Carradale – Port Ellen 2. [redacted]

3.5.4. Technical feasibility

Sections 2.6 and 2.7 provide further information on technical feasibility of these projects, in addition to the technical aspects discussed in this chapter.

3.5.5. Benefits to customers

The preferred options will facilitate the decarbonisation of homes and businesses across the Islay - Jura archipelago and support the potential connection of additional generation projects at a distribution level. It will also support decarbonisation and expansion of the local whisky industry.

The preferred option will also ensure a more reliable network to the island group and network compliance without reliance on Bowmore Power Station while meeting our Islands Resilience Policy in the long term. The removal of reliance on DEG also delivers societal benefits with a reduction in emissions envisaged, especially in fault situations.

3.5.6. Impacted assets or programmes of work

Relevant assets affected by proposed works to deliver the Inner Hebrides: Port Ann - Carradale GSP interventions are shown in Table 20. As shown, this captures impacts driven by both the interventions recommended to be progressed within RIIO-ED2, and those which are proposed to be taken forward at later dates.

Asset	Related works	Delivery date
Batt 1 Windfarm	New 33kV circuit Carradale GSP – Port Ellen No.1	2027/28
Batt 3 Windfarm	New 33kV circuit Carradale GSP – Port Ellen No.2	2027/28
Port Ellen 33kV Switchboard	New 33kV switchboard required to connect new incoming circuits and associated ancillaries	2027/28
Port Ellen Substation	Port Ellen Auto Changeover Scheme	2027/28
Port Ann GSP	New 33kV circuit from Port Ann to Jura	2032/33
New 33kV circuit from Port Ann to Islay.	Additional Jura – Islay Submarine cable	2032/33
Existing 33kV line from Port Ann to Islay	Reconductoring of existing 33kV circuit from Port Ann to Jura and from Islay to Knocklearach	2039/40

Table 20: Assets impacted by Islay - Jura proposals in RIIO-ED2

3.5.7. Alignment with business strategy and commitments

3.5.7.1. Alignment with licence, statutory obligations and Business Plan in RIIO-ED2

Table 21 summarises SHEPD and Ofgem positions on the interventions at RIIO-ED2 Final Determinations, and any changes made in the interim period. The reasons for affirming or changing recommended solutions are detailed in this application.

Area	Original proposal	Ofgem position	Current proposal
HOWSUM	Possibility of second circuit to Islay and Jura.	Formed part of original HOWSUM scope.	Proposal to install 2 new circuits from Carradale to Port Ellen in RIIO-ED2. Additional works identified for delivery in future price controls.

Table 21: Summary of positions on Islay - Jura projects in RIIO-ED2 Business Plan and HOWSUM 2025 submission.

3.5.7.2. Alignment with licence, statutory obligations and Business Plan for future price control periods

The RIIO-ED3 works associated with this option are the construction of additional 33kV circuits between Port Ann GSP and Knocklearach on Jura, and between Jura and Islay. We would also be installing a 33kV auto-close scheme at Port Ellen in RIIO-ED3.

Longer term works are also required, specifically the reconductoring of the existing Lochgilphead – Knocklearach and Bowmore – Knocklearach 33kV circuits by 2040.

3.5.8. Project delivery and monitoring plan

Please refer to Section 2.7 for our general approach to project delivery and monitoring, which will apply to this project.

3.5.8.1. Delivery strategy

To maximise efficiencies and deliver the most efficient solution for our customers, [redacted]

3.5.8.2. Managing and monitoring delivery

See Section 2.7 for information on our standard approach to managing and monitoring delivery, which is also applicable to this project.

3.5.8.3. Project delivery programme

The project delivery programme is forecast to span a four year period. Indicative activities are noted at Table 22.

Activities	Projected delivery
Early project activities	2024/25
Desktop route feasibility assessments and detailed route surveys	2025/26
Construction activities	2027/28

Table 22: Project delivery programme for Inner Hebrides: Islay - Jura (Option 2)

The installation of the two marine cables is forecast for delivery within the summer window of 2027 subject to contractor availability and consents. Final onshore network construction, testing and commissioning is anticipated to be concluded before the end of March 2028.

3.5.8.4. Procurement and commercial strategy

See Section 2.7 for information on procurement challenges which applies across all recommended projects.

- **Procurement challenges**

[redacted]

[redacted] This information will only become available as we approach the market with the project and are given their vessel availability.

- **Contracting approach – submarine cable**

SHEPD will again look to contract for the submarine cable elements of this work [redacted].

- **Contracting approach - onshore**

[redacted]

- **Procurement activities**

Table 23 sets out the anticipated procurement activities for the Inner Hebrides: Islay – Jura project.

Package	Package description	Procurement strategy	Comments	Required completion / delivery date
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 23: Inner Hebrides: Islay – Jura procurement activities

- **Work carried out to date**

SHEPD has carried out some initial feasibility assessment work on this project:

- Submarine cable landfall assessments via aerial photography
- Desktop assessment of possible land route
- Desktop studies for detailed marine route feasibility including site visits, informed by landfall assessments

- Marine survey works information pack developed to go to survey market

3.6. Further cost information

3.6.1. Development funding

3.6.1.1. HOWSUM development funding: Islay-Jura RIIO-ED2 projects

The development costs for projects proposed to be delivered in RIIO-ED2 are estimated in Section 2.6.6. The £20.6m development fund agreed at RIIO-ED2 Final Determinations is sufficient for our development activity related to RIIO-ED2 work in this island group. However, in order to facilitate early development work of our RIIO-ED3 Islay-Jura projects, we have requested additional allowances as detailed in 3.6.1.2. On the basis of our process for netting off the pre funded development costs as detailed in Section 2.6.6, the existing development funding baseline allowance will cover all development requirements for this island group.

Development activity	Detail	Estimated cost	Funding status
Route feasibility, detailed design and consenting	[redacted]	[redacted]	Funded through existing development funding allowance
		£0.00m	New development fund request

Table 24: HOWSUM development funding for Inner Hebrides: Islay Jura RIIO-ED2 projects (2020/21 prices)

3.6.1.2. HOWSUM development funding: Islay-Jura RIIO-ED3 projects

In order to deliver works required in RIIO-ED3 for this island group, we need to start project development in RIIO-ED2. Given the uncertainty around network requirements, we did not include a funding request at RIIO-ED2 Business Plan stage. We have now forecast additional development funding requirements, set out in Table 25. These relate to progressing the second 33kV circuit from Port Ann GSP – Knocklearach, the second circuit between Islay and Jura, and the refurbishment of the existing Jura 33kV radial OHL. Given our process for netting off the prefunded development costs as detailed in Section 2.6.6, the existing development funding baseline allowance will cover off all development requirements for this island group.

Development activity	Detail	Estimated cost	Funding status
Route feasibility	[redacted]	[redacted]	Funded through existing development funding allowance
		£0.00m	New development fund request

Table 25: HOWSUM development funding for Inner Hebrides: Islay-Jura RIIO-ED3 projects (2020/21 prices)

3.6.2. Cost efficiency

3.6.2.1. Efficiency in cost estimating

We have used all available information to provide the most accurate forecast view of costs within this submission. To achieve this, we have:

- Identified comparable completed projects to estimate costs in this submission.
- Identified comparable projects in development to estimate tender parameters.

Further detail as to how we have estimated costs is included in sections 2.6 and 3.4.1.2.

3.6.2.2. Efficiency in procurement and delivery

[redacted] As noted at Section 3.5.8.1, to maximise efficiencies and deliver the most efficient solution for our customers, [redacted].

[redacted]

The project will also look to realise efficiencies in our onshore works, [redacted]

3.6.3. Closely Associated Indirects

As for all projects, a factor of 10.8% has been applied to the total project cost to account for the cost of CAIs. Please see Section 2.6.5 for further information on this cost, and Section 3.1 for the specific CAI cost adjustment associated with our Islay - Jura RIIO-ED2 interventions.

3.6.4. Key cost drivers

Given the current stage of development of this project the key cost drivers are similar to the cost driver information contained in Section 2.6.2.

3.6.5. Areas of ongoing uncertainty

Sections 2.6 and 2.7 provide information on areas of ongoing uncertainty which apply across our recommended projects. In this section we include in more detail on further project-specific areas of uncertainty.

3.6.5.1. Offshore

- Submarine cable landfall: [redacted]

[redacted]

- Offshore geological features: [redacted]
- Fishing interaction and new routes: [redacted]

3.6.5.2. Onshore

- Circuit routing: [redacted]
- Circuit design: [redacted]
- Substation works: [redacted]

3.6.6. Allowances for project risk and risk register

Our approach to quantifying risk for these projects is set out in Section 2.7.7.

3.6.6.1. Standard risk allowance

The associated risk register for the standard risk allowance is detailed in Appendix 2. This provides an estimated maximum cost of the risk and associated likelihood of the risk being incurred. We have estimated a standard risk allowance of [redacted] for Inner Hebrides: Islay - Jura which is included within our adjustment request.

Risk allowance (£m, 2020/21 price base)	**Total standard risk attributed to works in RIIO-ED2**
Standard risk value	[redacted]

Table 26: Summary of standard risk allowance for Inner Hebrides: Islay – Jura

3.6.6.2. Extraordinary risk allowance

We have engaged with Ofgem to explore the introduction of a cost adjustment mechanism in RIIO-ED2 [redacted] (see Section 2.7.7). As Ofgem is minded not to introduce a cost adjustment mechanism to cover these costs, we have included an associated allowance request in this submission. Without this allowance, [redacted] which affects our ability to carry out our business. We have estimated that it would be reasonable to apply an allowance calculated at approximately [redacted] of all execution stage costs across all relevant projects. For Islay-Jura within RIIO-ED2 this equates to an allowance adjustment of [redacted], set out in Table 27.

Extraordinary risk allowance (£m, 2020/21 price base)	**Estimated cost**
Inner Hebrides: Islay - Jura RIIO-ED2 execution stage costs	[redacted]
Application of extraordinary risk allowance provision	[redacted]
Inner Hebrides: Islay - Jura extraordinary risk allowance	[redacted]

Table 27: Extraordinary risk allowance for Inner Hebrides: Islay – Jura

3.7. Stakeholder engagement

3.7.1. Recent engagement

We have continued to engage with stakeholders on the future energy needs for the Inner Hebrides network area. This includes Regen engagement to gather additional energy insights.

3.7.1.1. Webinar - February 2024

We ran a specific webinar focused on the Inner Hebrides on 29th February 2024. Sixteen stakeholders attended this event with their feedback informing our overall approach and the material within this application. The event provided background on the local network, the drivers for change, and our approach to developing options. We also covered the development of our Islands Resilience Policy as well as an overview of the DFES projections for the area.

Stakeholder feedback was:

- Grid reinforcement is seen as key to facilitating local net zero ambition
- Electrification seen as a potential solution to fossil fuel heat decarbonisation so total energy demand needs to be considered, not just electric
- There is a strong appetite for community owned generation in the Inner Hebrides
- Need to be aware of local industrial clusters with significant net zero ambition which could rely on electrification e.g. whisky distilleries.
- Feedback was mixed on our Islands Resilience Policy. It was felt that it needed to be further informed by an increased understanding of potential local load growth
- Stakeholders are keen to see local proposed large generation projects considered as an integrated part of the HOWSUM work

3.7.1.2. Webinar – September 2024

On 11th September 2024 we held a webinar to provide an update to stakeholders on the whole energy system analysis being undertaken through HOWSUM and to seek their views on the drafting of our Port Ann and Carradale GSP SDP. Seven stakeholders attended this event with their feedback helping to shape our proposals for the January 2025 submission, as well as informing our approach to the SDP.

- Stakeholders were in general agreement that our SDP process was fit for purpose.
- Local energy groups and generators are keen to collaborate with SHEPD on achieving network resilience and managing demand. There was particular interest in provision of flexibility services.
- Growth in house building on the islands was highlighted as a key consideration.
- There remains a strong appetite for community energy projects with both solar and run of river hydro highlighted as key considerations.
- Stakeholders are keen to be kept informed as the process develops, with webinars the preferred method of communication.
- Emphasis on the importance of capturing distillery decarbonisation/electrification ambition on Islay.

3.7.1.3. Roundtable – December 2024

On 18th December 2024 we held an online roundtable session to provide stakeholders with an overview of the optioneering process we had worked through as part of HOWSUM and present the preferred option that had emerged from that process. Feedback from the seven stakeholders in attendance has helped with refining this submission and has raised points for further collaboration on the continual refreshment of our SDPs.

- Recognition that there is significant uncertainty in the future demand profile of the Islay/Jura/Colonsay island group with businesses and individuals keen to keep SHEPD informed as plans progress.
- Stakeholders are keen to understand what the plans mean in practice for connections on the island.
- Stakeholders are supportive of the plans in principle, but keen to continue to be involved as they are developed.
- Appetite to understand what removal of reliance on Bowmore Power Station could look like in practice and if there will be scope for third party provision of alternative options to be considered.

3.7.1.4. Bilateral engagement

In addition to the SHEPD bilateral meetings listed below Regen have also engaged bilaterally as part of their work.

- Scotch Whisky Association (SWA)
    - 24th October 2023: Discussion on the range of decarbonisation strategies employed by distilleries both on islands and the mainland.

- June/July 2024: Series of meetings to pull together a questionnaire and engagement plan to understand the future electrical demand of distilleries on Islay and Jura. This culminated in a webinar and then distribution of a questionnaire to SWA members.

- Argyll and Bute Council
    - Regular engagement throughout 2023 and 2024 providing ongoing updates on the HOWSUM process, gathering insights to inform the DFES and providing targeted engagement to ensure synergies with local development plans.
- Community Energy Scotland
    - 27th May 2024: Meeting with Carbon Neutral Islands project officers to provide an update on HOWSUM work and signpost to upcoming consultations.
- SSEN Transmission
    - 1st December 2023: We provided an overview of Regen's insights work and asked for their feedback and input.
    - 16th August 2024: Update on shortlisted options identified via the HOWSUM process and discussion on operational implications.
- Highlands and Islands Enterprise (HIE)
    - 26th June 2024: Overview of HOWSUM process and plans for the Inner Hebrides to allow HIE to engage their clients in the Inner Hebrides.
- Islay Energy Trust
    - 5th June 2024: Outline of HOWSUM programme and initial discussion of plans for capturing additional industrial insights, particularly on Islay.
    - 12th July 2024: Update on progress on HOWSUM work and engagement with the whisky sector. Feedback on our work to date and offer of help with circulation of distillery questionnaire.

3.7.1.5. SDP engagement

Our draft Port Ann and Carradale GSP SDP[46] was published for consultation on 7th November 2024. The consultation closed on 10th December 2024, with four formal responses received. These responses were assessed using the RICE methodology with feedback summarised below.

- Several significant developments in the area were highlighted for consideration in future iterations of the DFES.
- It is critical to improve network capacity for the economic development of remote/rural communities.
- The need for continued alignment of SHEPD network planning with the local council's Local Development Planning process was called out.

These responses will be addressed in the finalised SDP publication, as well as informing our engagement on the annual update to the plan. Stakeholders will also receive a direct response to their individual consultation feedback. Our finalised SDP will be published on our website.[47]

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46 Survey Details | Port Ann and Carradale Grid Supply Points Strategic Development Plan Consultation

47 Publications & Reports - SSEN

3.7.2. Stakeholder engagement impact

Table 28 sets how we have responded to key feedback.

STAKEHOLDERS SAID	WE DID
They need further clarity on our plans and there is a need for continued engagement.	We have offered additional opportunities to engage with us through dedicated bilateral discussions and held webinars to update stakeholders on our progress. We held further engagement through 2024 ahead of our January 2025 submission.
We need to consider the community energy pipeline	We worked with Regen to further engage with local communities and industries to understand future requirements and opportunities, and ensured this information was reflected in our DFES.
We need to consider demand for additional housing provision in the area	We have engaged with Argyll and Bute Council on their local housing strategies and plans and have received more granular responses on local housing numbers through our DFES engagement process.
There is appetite for local participation in provision of flexibility services for island networks	We published an RFI in August 2024, looking to further gauge the appetite and availability of flexibility providers in the Scottish islands.
There is a need to better understand the future decarbonisation pathways of the whisky industry in Islay and Jura	Engaged with Scotch Whisky Association and Islay Energy Trust to develop and then distribute a targeted questionnaire, gathering insights on the decarbonisation plans of the whisky sector in the area. The results of this questionnaire have been assessed and incorporated into our analysis to supplement the DFES projections.

Table 28: Acting on stakeholder feedback under the HOWSUM workstream

3.8. Conclusion - Inner Hebrides: Islay - Jura

SHEPD has identified that the best long term strategic option for the Islay – Jura network is Option 2, which proposes the following:

- During RIIO-ED2:
  - A new 33kV circuit from BAT Wind I (Carradale GSP) – Port Ellen
  - A new 33kV circuit from BAT Wind III (Carradale GSP) – Port Ellen
- During RIIO-ED3:
  - A second Port Ann – Knocklearach 33kV circuit
  - A second Islay – Jura 33kV circuit
  - A 33kV auto-close scheme at Port Ellen
- By 2040:
  - Reconductoring of Lochgilphead – Knocklearach and Bowmore – Knocklearach 33kV circuits

The first two Carradale GSP circuits will be delivered within RIIO-ED2 [redacted] to Islay and Jura. On completion of the works, Bowmore Power Station will not be utilised to maintain [redacted] due to the adequate capability of the new 33kV circuits.

The capital cost of Option 2 is forecast to be [redacted] during RIIO-ED2 and [redacted] in future price controls. This option meets all primary drivers, is the most cost-effective option [redacted] in addition to providing sufficient capacity for demand growth until at least 2050.

In conclusion, SHEPD aims to pursue Option 2 ensuring that we continue to provide a resilient network, with sufficient capacity, and lower carbon footprint all whilst ensuring a cost-effective engineering solution.

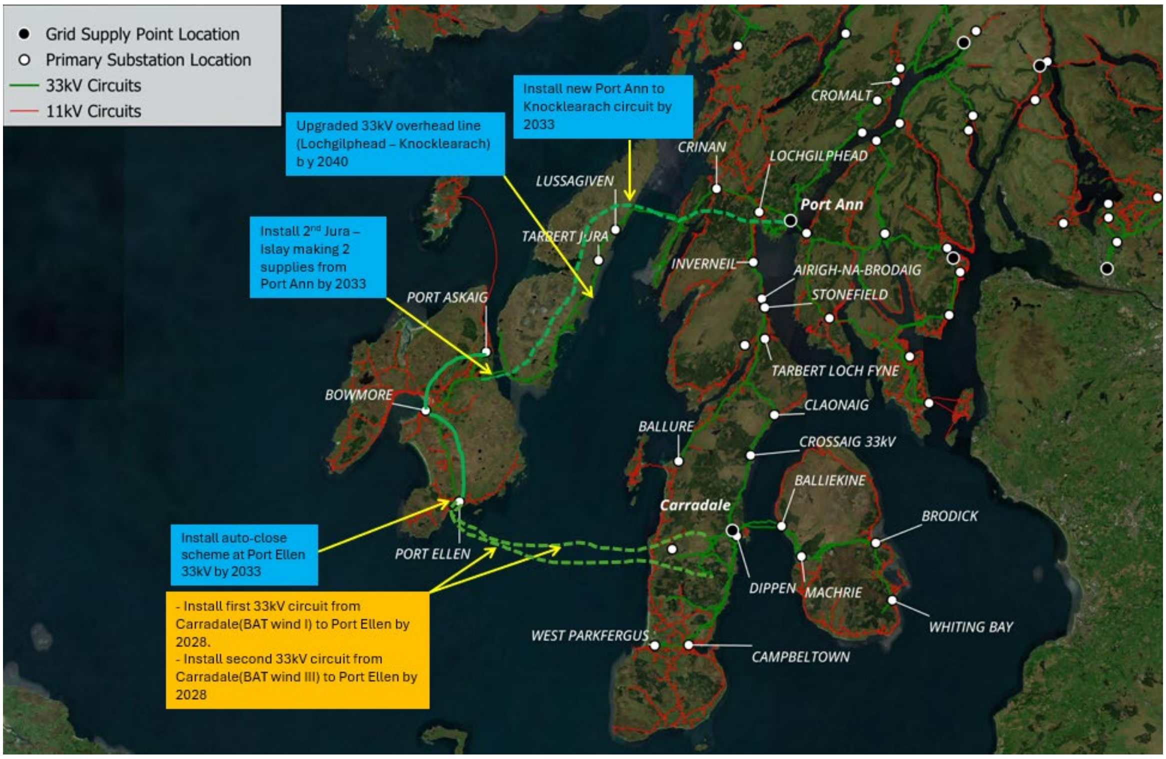

Figure 19: 2050 strategic plan for Islay and Jura

Summary of adjustment request – Inner Hebrides: Islay - Jura

Adjustment summary (£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Total adjustment for Inner Hebrides: Islay - Jura	-	-	[redacted]	[redacted]	[redacted]	[redacted]

Table 29: Inner Hebrides: Islay - Jura allowance adjustment summary

4. ORKNEY

Our analysis of the Orkney group demand and generation requirements to 2050 indicates that the existing network infrastructure needs to be supplemented from RIIO-ED2 to meet future island needs, remove reliance on Kirkwall Power Station, and maintain system resilience.

Our 2050 strategic plan identifies the requirement for investment in RIIO-ED2 and RIIO-ED3. Our findings are summarised as:

- A new 57km 66kV circuit from Thurso South to a new primary at South Ronaldsay via John O'Groats on the mainland, installed by 2028/29, initially run at 33kV but with the expectation to utilise at 66kV, and to upgrade the local network to enable this, in RIIO-ED3.
- The identification of two potential network development pathways from RIIO-ED3, subject to evolving demand and generation needs: a demand resilience pathway, and a generation export pathway. Under either pathway further works would be required in RIIO-ED3 to upgrade and supplement the network. Upgrading of 33kV circuits to 66kV would be required under the demand resilience pathway, and a second transmission link would be required under the generation export pathway.
- Reliance on DEG will be removed in 2033 either through additional network infrastructure, or use of flexibility. The means by which this will be achieved will be determined during the development of our RIIO-ED3 plans for Orkney.

In this application we are seeking funding for a new 66V specification circuit to Orkney but which will initially be operated at 33kV. We have identified this as the optimum first stage of our 2050 plan, allowing us to maintain optionality on RIIO-ED3 interventions. This circuit will be built at 66kV specification, allowing it to be upgraded to operation at 66kV in future if needed. It is anticipated that this project will straddle RIIO-ED2 and RIIO-ED3 price control periods, with construction starting in 2026/27 and completing in 2028/29.

We will assess demand and generation needs as part of our RIIO-ED3 Business Plan preparation and will provide a recommendation at that point on which pathway to progress. We also seek additional development funding as part of this application to progress early stage activities, as well as funding to cover risk and CAIs. Table 30 summarises our adjustment request for Orkney, with more detail provided at Section 4.1.

Adjustment summary (£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Total adjustment for Orkney	-	-	-	[redacted]	[redacted]	[redacted]

Table 30: Orkney allowance adjustment summary

Further background on the Orkney network is included in the Orkney – Thurso South GSP SDP.48 The detailed proposals and justification for the Orkney interventions are set out in Appendix 4A – Orkney EJP, Appendix 4B – Orkney Standard CBA, Appendix 4C – Orkney CEM CBA 1 and Appendix 4D – Orkney CEM CBA 2. The following sections cross-reference and summarise these documents.

4.1. Allowance adjustment

48 Survey Details | Thurso South Grid Supply Point Strategic Development Plan Consultation

Table 31 sets out the detail of the requested allowance adjustment for Orkney in this submission. This adjustment covers the portion of works which are required within RIIO-ED2 to deliver the preferred long term solution.

Adjustment summary (£m, 2020/21 price base)	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**Total**
Total Orkney forecast[1]	**-**	**-**	**-**	[redacted]	[redacted]	[redacted]
Delivery costs[2]	-	-	-	-	[redacted]	[redacted]
Development costs (pre-funded)[3]	-	-	-	[redacted]	[redacted]	[redacted]
Development costs (request)[4]	-	-	-	-	[redacted]	[redacted]
Standard risk allowance[5]	-	-	-	[redacted]	[redacted]	[redacted]
Extraordinary risk allowance[6]	-	-	-	-	[redacted]	[redacted]
CAIs[7]	-	-	-	[redacted]	[redacted]	[redacted]
Total adjustment[8]	**-**	**-**	**-**	[redacted]	[redacted]	[redacted]

1. 'Total forecast' means all project costs (including development costs, capital and operating costs, risk and CAIs) before the deduction of any applicable HOWSUM development funding baseline allowance.
2. 'Delivery costs' are project costs before the addition of development, risk and CAI costs. These are estimated costs provided prior to carrying detailed procurement and delivery assessment processes. See Appendices 4A to 4D for detail.
3. 'Development costs (pre-funded)' is the amount of development costs which has been covered by the existing HOWSUM development funding baseline allowance of £20.6m. See Section 2.6.6.
4. 'Development costs (request)' is the amount of additional development funding required to progress the relevant island interventions, which the HOWSUM development funding baseline allowance does not cover.
5. The standard risk allowance covers foreseeable and fairly well understood types of risks. See Section 2.7.7 and our risk registers for more detail.
6. The extraordinary risk allowance covers [redacted]. It has been applied as [redacted], after addition of CAIs. See Section 2.7.7.
7. CAI costs are calculated as 10.8% of total project costs, after addition of project risk allowances. See Section 2.6.5.
8. Total adjustment = (Total Orkney forecast – Development costs (pre-funded))

Table 31: Orkney allowance adjustment

4.2. Background to investment

The Orkney islands are currently supplied from Thurso South GSP through two 33kV submarine cables. There are [redacted] circuits which supply the rest of the Orkney demand from Scorradale substation. There are [redacted] 33kV / 11kV primary substations on Orkney, supplying approximately 14,058 customers. Kirkwall Power Station provides back-up power supplies to the islands in the event of an interruption to submarine cable supplies.

Our analysis of the Orkney network in this application builds on the existing network, including the replaced PFE3 cable, and proposes further investment in the network to meet our net zero commitments.

4.3. Needs case and optioneering

4.3.1. Primary and secondary investment drivers

The primary investment driver for completing this work is increased demand based on our 2023 DFES projections, which indicate demand will be [redacted] MW by 2050. The existing Orkney network will not support projected demand beyond 2029 without additional network investment.

There are also several secondary drivers for our proposals. Whilst these are longer term drivers, we considered them both in the development of our longer-term strategy and in the sizing of cables and other circuit elements within this application. These are:

1. Future generation requirements on the islands: We have investigated future distribution-connected generation, ensuring cable sizing will allow the forecast import and export of power between the islands and the GB mainland. The works will be required within both RIIO-ED2, RIIO-ED3 and subsequent price control periods.
2. Future resilience needs of the islands and decarbonisation of DEG: Currently Kirkwall Power Station provides back-up supplies for the islands, [redacted]. However, the generators are aging and are a significant source of emissions. Emissions are a further driver for our proposals in this regard with a target of decarbonisation by the end of 2033. We have reviewed the network in line with our DEG strategy and Islands Resilience Policy. This review indicates that further interventions will be required to allow removal of reliance on DEG and maintain resilient supplies to our customers.

In addition to these drivers there are a number of other factors we have taken into account including the potential use of flexibility to defer traditional assessment, and the impact of SSEN Transmission's High Voltage Alternating Current (HVAC) project works. Further information is included on these aspects is included in the Orkney – Thurso South GSP SDP and Appendix 4A – Orkney EJP.

4.3.2. Methodology for assessing options and for selection of the preferred option

Consistent with both our SDPM and the regulatory requirements of the HOWSUM described in Sections 2.3 and 2.4, we have taken a broad whole system perspective on the future needs for the Orkney islands. The following sections detail how we have assessed and selected our preferred option.

4.3.2.1. Whole System opportunities

We have consciously identified, assessed and selected options through a whole system lens to take account of energy requirements in 2050, as well as the interactions with Transmission, embedded generation and potential future third party services, energy sources and demands. The solutions recommended under the HOWSUM re-opener application are selected based on their ability to form part of a long-term, whole system solution for the Orkney islands.

4.3.2.2. Flexibility opportunities

Use of flexibility to defer investment

We have considered flexibility in the short term and longer term in the Orkney islands. Whilst there is limited market capability in RIIO-ED2, tested through our recent RFI (Section 2.3.3.1) and discussed below, we need to work with stakeholders to develop flexibility for use in the longer term to efficiently meet the Islands Resilience Policy. This is particularly the case for the generation export pathway identified in our optioneering (see Section 4.5).

Status of flexibility in this area

The RFI we launched in August 2024 revealed parties that could be willing to provide flexibility services, and we are continuing conversations with relevant stakeholders as we develop our procurement strategy in these locations. However, the RFI has not identified the volume of flexibility services needed in the short term that could be used to remove the reliance on DEG. While flexibility potential exists across assets, the primary obstacles include high costs, infrastructure delays, customer engagement barriers, and connection contracts. Flexibility solutions will likely require relatively long-term, guaranteed income contracts and infrastructure investment support to overcome these challenges and expand renewable integration across the islands.

Potential future application analysis

We believe that there is a marginal case for flexibility for a defined period in RIIO-ED2. [redacted] ahead of delivery of our proposed new circuit from Thurso South – South Ronaldsay, as described in the following sections. However, use of flexibility is not the most efficient solution when assessed under all DFES, and our RFI has indicated that the market is not sufficiently mature at this time.

There is a strong case for flexibility as part of our generation export pathway from the end of RIIO-ED3. This would be needed to provide supply resilience in the event of an [redacted] condition ahead of implementation of a second transmission link to Finstown. We will work with potential providers to facilitate the nascent flexibility market if this pathway is confirmed as optimum.

4.3.2.3. Interactions with transmission works

It is critical to ensure that a whole system view is taken of the future requirements for Orkney. There is currently no transmission network on the Orkney islands, however there are significant transmission works planned for this part of the GB transmission system. We have engaged with SSEN Transmission to understand planned transmission works affecting Orkney and how they may impact our developments.

Currently there are a number of grid constraints limiting the output of on-island generation and preventing the development of new renewable projects. There is significant interest in future transmission-contracted generation. To meet the contracted generation and ongoing applications SSEN Transmission is developing a project to install a new GSP at Finstown [redacted] and a HVAC transmission system between Finstown in Orkney and Dounreay in Caithness, capable of transmitting up to 220MW of power. The project includes [redacted] onshore HVAC cable and [redacted] submarine HVAC cable.

The new Finstown GSP will help enable generation customers on Orkney to export the electricity they produce to the wider GB network. This scheme should also increase network resilience with an additional transmission link to Orkney. The Finstown GSP and transmission link is expected to be commissioned and energised in 2028.

Additionally, we are aware that there a number of proposed marine generation projects that could connect to offshore transmission networks in the seas around the Orkney islands. We will continue to monitor this situation to understand opportunities to co-ordinate with such works.

4.3.3. Options considered

Ten study options have been developed to meet our needs case to 2050, along with a 'do nothing' counterfactual. These are summarised in Table 32.

Option name	Summary
Option 1	• Do nothing; not compliant with future demand or generation requirements.
Option 2 (33kV)	• 33kV reinforcement of existing PFE and PFW (Pentland Firth West cable) by 2045, with three new submarine cables (Thurso South and South Ronaldsay via John O'Groats between 2024-2029, Thurso South and Scorradale between 2029-2033 & Thurso South and South Ronaldsay via Hoy between 2040-2050) and a second transmission link by 2040
Option 3 (33kV)	• 33kV reinforcement of existing PFE and PFW by 2045 with four new submarine cables (Thurso South and South Ronaldsay via Hoy between 2024-2029, two circuits between Thurso South and Scorradale between 2029-2033 & Thurso South and South Ronaldsay via Hoy between 2040-2050) and a second transmission link by 2050
Option 4 (33kV)	• 33kV reinforcement of existing PFE and PFW by 2045, with addition of three submarine cable routes (Thurso South and South Ronaldsay via John O'Groats between 2024-2029, Thurso South and Scorradale between 2029-2033 & Thurso South and South Ronaldsay via John O'Groats between 2040-2050)and a second transmission link by 2040
Option 5 (33kV)	• 33kV reinforcement of existing PFE and PFW circuit with addition of three submarine cable routes (submarine cable and onshore UG cable between Thurso South and South Ronaldsay via John O'Groats between 2024-2029, Thurso South and South Ronaldsay via Hoy between 2029-2033 & Thurso South and Scorradale between 2040-2050) and a second transmission link by 2040.
Option 6 (33kV)	• 33kV reinforcement of existing PFE and PFW circuit by 2045, with addition of three submarine cable routes (submarine cable and onshore UG cable between Thurso South and South Ronaldsay via John O'Groats between 2029-2033, Thurso South and South Ronaldsay via Hoy between 2024-2029 & Thurso South and Scorradale between 2040-2050) and a second transmission link by 2040.
Option 7 (66kV)	• Additional 66kV cable (Thurso South - South Ronaldsay via John O'Groats between 2024-2029) followed by 66kV upgrade of PFW and PFE.
Option 8 (66kV)	• 66kV upgrade of PFW and PFE in RIIO-ED2 followed by additional 66kV cable (Thurso South - South Ronaldsay via John O'Groats between 2025-2023).
Option 9 (66kV)	• Install 66kV Thurso South - South Ronaldsay between 2024-2029. Upgrade PFW circuit to be running at 66kV between 2029-2032 and a second transmission link by 2040
Option 10 (66kV)	• Install 63km 66kV Thurso South - South Ronaldsay via Hoy between 2024-2029. Upgrade PFW and PFE circuits to be running at 66kV between 2029-2032
Option 11 (66kV)	• One 66kV submarine circuit on the same route between 2024 and 2029, a 66kV submarine cable and onshore OHL between Thurso South and South Ronaldsay via John O'Groats between 2029 and 2032 and a second transmission link by 2040

Table 32: Options considered for Orkney

We reduced this list of options using power system analysis to simulate the technical operation of each option on the network, resulting in five options that are technically feasible, cost effective and deliverable. The results of the CBA for the five options are discussed in more detail in the following sections.

A further option was subsequently developed based on Option 7, but with initial operation of the new 66kV circuit from Thurso South to South Ronaldsay at 33kV. This is referred to as Option 7A.

It is important to note that the options aim to deliver the whole system solution looking out to 2050. Elements of the options will be delivered in a phased approach driven by network need. The phasing of the activities within the options are discussed in the following sections and are laid out in Appendix 4A – Orkney EJP, Appendix 4B – Orkney Deterministic CBA, Appendix 4C – Orkney CEM CBA 1 and Appendix 4D – Orkney CEM CBA 2.

4.4. Cost benefit analysis and engineering justifications

4.4.1. Summary of cost benefit analysis

We undertook a deterministic CBA for each of the five shortlisted options. This is provided at Appendix 4B – Orkney Standard CBA. The CEM tool has also been used to understand the relative benefits of flexibility in both RIIO-ED2 and RIIO-ED3 and is provided at Appendix 4C – Orkney CEM CBA 1 and Appendix 4D – Orkney CEM CBA 2. A summary of the conclusions is provided in the following sections.

4.4.1.1. Cost and other key assumptions

We set out general information on our assumptions and data sources in Section 2.6. The cost estimates presented for the Orkney interventions use the specific assumptions detailed in Table 33. More detail on our cost assumptions is included in the accompanying Appendices 4A, 4B, 4C and 4D.

As set out in Section 2.6 SHEPD has developed a cost book in the preparation of our options analysis to ensure a consistent approach to project estimating has been taken for similar assets. This cost book is based on internal SHEPD unit rates, Ofgem RIIO-ED2 unit rates, outturn costs for comparable projects, and unit rates from our SEPD licence area for voltages exceeding 33kV. Assumptions for 66kV submarine cable costs have been determined [redacted]. The use of 66kV equipment would be SHEPD's first installation of 66kV assets and, as such, we do not have our own cost benchmarks available - the current estimates are based upon a best view from the SEPD licence area. [redacted]

Cost / assumption type	Assumptions	Justification and explanation
Submarine cable	[redacted]	SHEPD has not previously installed 66kV cable. [redacted]
	[redacted]	[redacted]
Onshore 66kV network	Assumed costs will be similar to SEPD unit rates.	SHEPD has not previously procured or installed 66kV assets. [redacted]
OHL opex	Actual recent OHL inspection and maintenance costs.	This approach ensures the most accurate cost data is utilised across the CBAs

Cost / assumption type	Assumptions	Justification and explanation
Flexibility opex	Flexibility unit cost and flexibility volume.	Standard flexibility prices based on existing contract data
.DEG running costs	Actual DEG generation running durations and costs.	Based on recent outturn costs.
Loss reduction benefit	SHEPD internal loss calculator is used to determine the loss reduction benefit through different intervention types.	This approach ensures a common approach through all CBAs. The losses within the CBA include a standard calculation to monetise these reduced losses, along with the subsequent CO2 impact.
Customer Interruption (CI) and Customer Minutes Lost (CML) data	Actual SHEPD data.	The CBA tool utilises this data to calculate the benefit of avoided CIs and CMLs on the network after reinforcement.

Table 33: Orkney core cost assumptions

4.4.1.2. Orkney 2050 strategic plan option costs

The total combined costs for the strategic plan options are shown in Table 34. As noted above, these costs are based on a combination of SHEPD internal unit rates (C1), assumed submarine cable unit rates [redacted]. The costs also include expected substation reinforcement works to facilitate the installation of the proposed submarine cable routes. These costs are for the delivery of all elements of the 2050 strategic plan associated with that option, not only works and costs within RIIO-ED2.

Options	Description	Total (£m)
Option 2 (33kV)	33kV reinforcement of existing PFE and PFW with three new submarine cables, a second transmission link with interim use of flexibility (South Ronaldsay – John O'Groats route).	[redacted]
Option 3 (33kV)	33kV reinforcement of existing PFE and PFW with three new submarine cables, the second transmission link with interim use of flexibility (South Ronaldsay – Hoy cable route).	[redacted]
Option 7 (66kV)	Additional 66kV cable (operated at 66kV) followed by 66kV upgrade of PFE and PFW.	[redacted]
Option 8 (66kV)	66kV upgrade of PFE and PFW followed by additional 66kV cable.	[redacted]
Option 7A (66kV)	Additional 66kV cable (operated at 33kV during RIIO-ED2) followed by 66kV upgrade of PFE and PFW.	[redacted]

Table 34: Orkney option summary costs (£m, 2020/21 prices)

Table 34 shows that the least cost option is Option 7: Additional 66kV cable followed by upgrading of PFE and PFW to 66kV.

4.4.1.3. Orkney 2050 strategic plan deterministic CBA comparisons

The deterministic CBA results for technically feasible options are summarised in Table 35. The option with the best NPV under the deterministic CBA is Option 7. However, Option 7A retains additional optionality benefits through maintaining multiple future pathways: either continuing to run at 33kV to follow the demand resilience pathway, or to progress to run at 66kV to follow the generation export pathway.

Option	10 years	20 years	30 years	45 years	Whole life (55 years)
Option 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Option 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Option 7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Option 8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Option 7A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 35: Deterministic CBA results for Orkney - NPV at different intervals (£m, 2020/21 prices)

4.4.2. Application of Common Evaluation Methodology

The CEM tool has been used to identify whether flexibility could be a more efficient method to release capacity. For the Orkney islands strategic plan, we have looked at two separate use cases for flexibility: deferral of investment in RIIO-ED2, and deferral of the second transmission link to the islands required by 2033 under the generation pathway.

Flexibility option during RIIO-ED2

The CEM assessment shows the RIIO-ED2 expenditure relating to the commissioning of the preferred option (7A) could be deferred for one year, to take place in 2030. However, there are complexities and barriers for flexibility participation, particularly around ANM and grid access on Orkney. Recognising this, we will not defer Option 7A during RIIO-ED2. We will continue to monitor and support the development of flexibility resource that could provide flexibility services for use on Scottish islands in RIIO-ED3.

Flexibility to defer second transmission link

The CEM assessment shows that for the generation export pathway the second transmission link expenditure can be deferred for fifteen years under the CT scenario, from 2033 to 2048. There is deferral of seven years under the LW scenario, to 2040. As there is uncertainty on the commissioning year for the second transmission link that is dependent on the generation applications in Orkney islands, we propose the second transmission link is installed by 2040 and use the flexible solution identified in Options 2 and 3 for the [redacted] outage between 2033 and 2040.

4.4.2.1. Orkney CBA conclusions

Options 7, 7A and 8 demonstrate the optimum NPVs at this time (with Options 7 and 8 involving the same physical interventions with different phasing). Our whole system analysis has shown that there is significant uncertainty in the future requirements for the Orkney islands due to the potential for additional generation connections and transmission infrastructure. We therefore believe it is important to retain optionality for multiple pathways. Option 7A achieves this at minimal additional cost and is therefore our proposed solution. This approach is discussed further in the following sections. Please also refer to Appendices 4A to 4D for further details and context.

4.5. Preferred option

Our analysis has identified that there are two groups of diverging options for the future network between the Orkney islands and the Scottish mainland: a demand resilience pathway and a generation export pathway. The nature of the Orkney islands network leads to a need for whole systems thinking ensuring coordination between transmission and distribution to find the optimal solution. In this instance a proposed second 132kV link to Orkney has been assessed against, and in conjunction with, distribution solutions at 33kV and 66kV. The proposed solution involves installation in RIIO-ED2 of a 66kV submarine cable from Thurso South to South Ronaldsay and the operating of this circuit at 33kV in order to maintain optionality in the context of uncertainty in the region.

Our analysis suggests that the most efficient way to deliver each pathway is through Option 7 and Option 2 respectively. Both pathways can commence in RIIO-ED2 with the installation of a new 66kV circuit (initially operated at 33kV) between Thurso South and South Ronaldsay substation during RIIO-ED2 (Option 7A).

Our view is that Option 7A is the best proposal to maintain optionality through installation of 66kV equipment and initial operation at 33kV. Below we provide the key features of both 2050 strategic pathways for comparison. Our central case at this point is the Demand Resilience Pathway (Option 7A).

4.5.1. Description of key features

4.5.1.1. Demand Resilience Pathway - Option 7

This pathway would see additional capacity being delivered through distribution network upgrades at 66kV. It involves a new [redacted] 66kV circuit from Thurso South to South Ronaldsay via John O'Groats installed by 2029 as shown in Figure 20. The circuit includes a new 66kV OHL [redacted] from Thurso South to the landing point of the submarine cable (near John O'Groats) and a new [redacted] 66kV submarine cable between John O'Groats and Burwick. Approx [redacted] OHL and [redacted] 66kV onshore cable are installed between Burwick and South Ronaldsay. Further works would be required in RIIO-ED3 to upgrade the PFW and PFE circuits to run at 66kV between 2029 and 2033. This option is not reliant on a second transmission infeed to Finstown GSP and removes reliance on the existing DEG at Kirkwall [redacted].

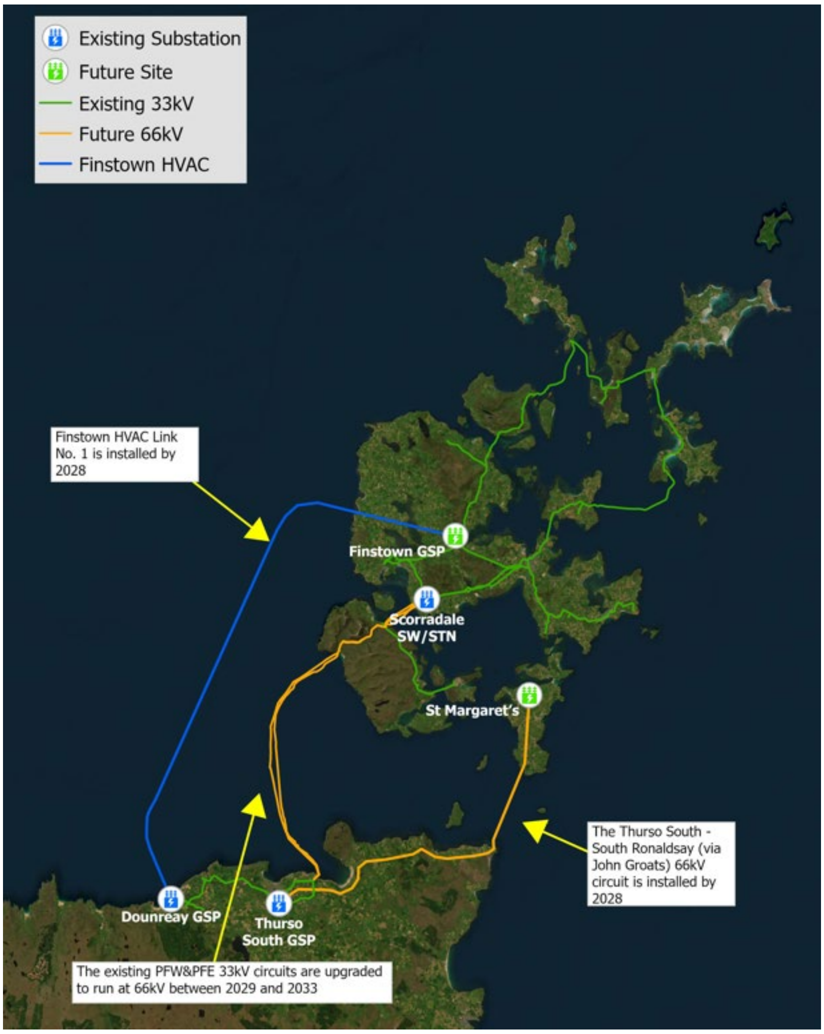

Figure 20: 2050 strategic plan for Orkney - Demand Resilience Pathway (Option 7)

4.5.1.2. Generation Export Pathway - Option 2

This pathway would see additional transmission assets providing additional capacity and retention of a 33kV distribution approach with incremental capacity. It also involves a new [redacted] 66kV circuit from Thurso South to a new primary at South Ronaldsay via John O'Groats. Again, it is proposed this circuit will be installed by 2028/29, as shown in Figure 21. Initially it will be connected into the 33kV network at Thurso South and on Orkney and operated at 33kV. Further works would be required in RIIO-ED3 to reinforce the local network at 33kV from Thurso South to Scorradale which would allow us to remove reliance on the existing DEG at Kirkwall [redacted]. There would also be longer term requirements for a second transmission link and a 33kV circuit from Thurso South – South Ronaldsay via Hoy and potential use of flexibility services ahead of the second transmission link being installed.

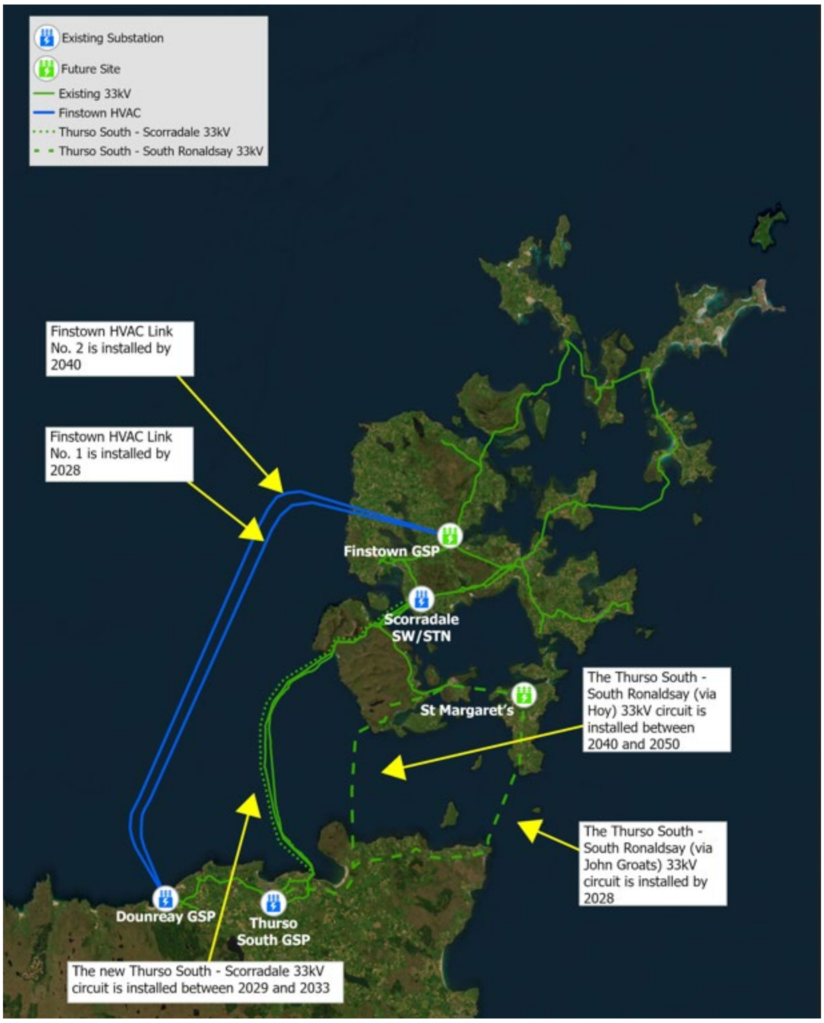

Figure 21: 2050 strategic plan for Orkney 2050 - Generation Export Pathway (Option 2)

4.5.1.1. Hybrid solution - Option 7A

This option would see additional capacity being delivered through distribution network upgrades at 66kV. It involves a new [redacted] 66kV construction circuit from Thurso South to a new primary at South Ronaldsay via John O'Groats on the mainland. It is proposed this circuit will be installed by 2028/29, as shown in Figure 22. Initially it will be connected into the 33kV network at Thurso South and on Orkney and operated at 33kV. Further works would be required in RIIO-ED3 to upgrade the local network to 66kV, and to upgrade the PFW and PFE circuits to run at 66kV between 2029 and 2033. This option is not reliant on a second transmission infeed to Finstown GSP and removes reliance on the existing DEG at Kirkwall [redacted].

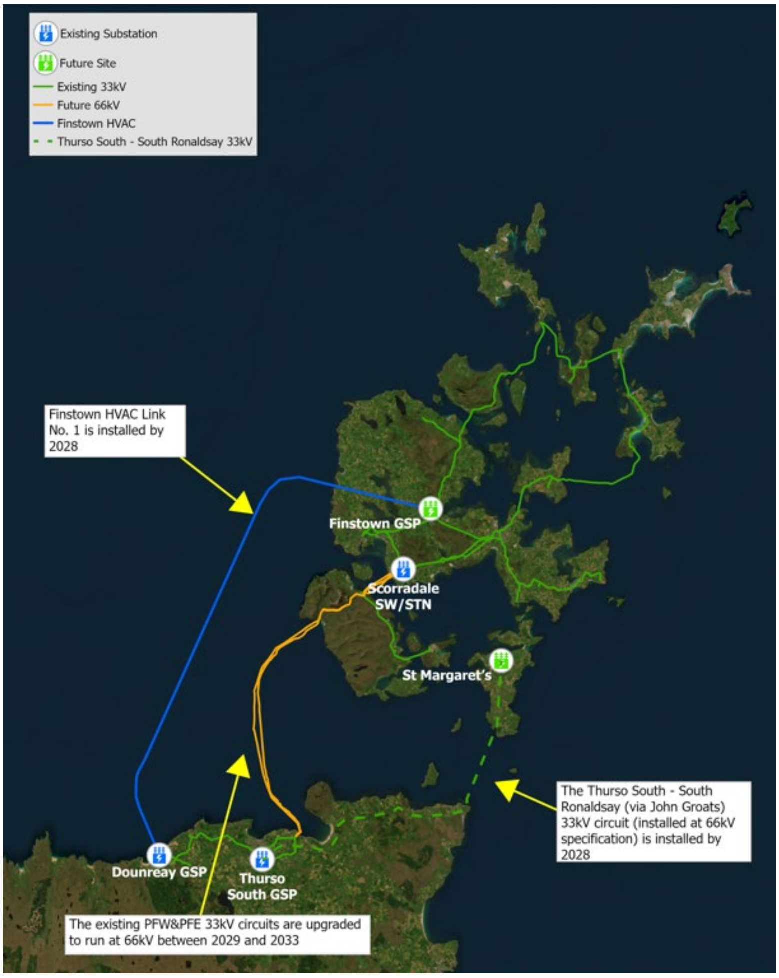

Figure 22: 2050 strategic plan for Orkney - Hybrid Solution (Option 7A)

Progressing Option 7A at this time is the best proposal to maintain optionality and to allow us to respond to the needs of the islands as they evolve over the coming years.

4.5.2. Expected outputs

Table 36 details key expected outputs associated with our recommended interventions to be delivered in RIIO-ED2 and early RIIO-ED3 based on Option 7A.

Project element	Key outputs	Forecast delivery dates[1]
Thurso South – South Ronaldsay	New 66kV OHL Thurso South – John O'Groats (Running at 33kV)	Forecast delivery 2027/28
	New 66kV OHL Burwick – South Ronaldsay (Running at 33kV)	Forecast delivery 2027/28
	New 66kV submarine cable John O'Groats – Burwick (Running at 33kV)	Forecast delivery 2028/29

[1] Delivery dates are estimates, not wholly within our control and will be refined as projects are further developed.

Table 36: Expected key outputs and years of delivery for Orkney interventions

4.5.3. Timing of investment and rationale for phasing interventions

Recognising the inherent uncertainty in predicting the demand and generation profiles of the Orkney islands in the future, we intend to implement a staged approach to the implementation of Option 7A. We propose to install a new circuit from Thurso South GSP to South Ronaldsay, built to 66kV specification but initially running at 33kV. All other elements of the preferred solution will be reviewed as part of our RIIO-ED3 Business Plan development to understand which pathway provides the optimum outcome.

Our long-term plan has been developed consistently with our broader approach to strategic investment. This process is described in more detail in sections 2.3 and 2.4. Further to our current analysis, our long-term optimum delivery strategy contains three main elements:

1. **Immediate requirements to progress in RIIO-ED2:**
    a. Near-term least regrets options that resolve immediate drivers and risks, whilst delivering solutions that form part of the least regrets solutions for 2050. This includes our proposal to progress a new circuit from Thurso South GSP to South Ronaldsay within RIIO-ED2, built to 66kV specification but initially running at 33kV. This [redacted] for our customers, whilst sizing the cable to meet future demands. This option is considered an integral piece of the majority of feasible solutions offered and facilitates optionality at later stages.
2. **Longer term whole system requirements**
    a. Capacity increase to the Orkney islands: There is a need to increase the capacity of the network to Orkney by 2029, i.e. augmenting the existing submarine cables or replacing with larger 66kV cables. Island storage will be assessed as an alternative along with flexibility as alternative solutions.
    b. Long term resilience for the Orkney islands: Additional distribution circuitry between the mainland and Orkney within RIIO-ED3 will help deliver longer term resilience to the island group taking advantage of the new transmission infeed from the HVAC link. This will remove our reliance on the aged diesel generation fleet by 2033 whilst also allowing other third-party options including hydrogen storage to further develop.

4.5.4. Technical feasibility

The preferred option has been technically assessed per the methodology and approach described in Sections 2.3 and 2.42.3. This feasibility assessment has been a desktop exercise and, given the significant challenges in carrying out activities in the Pentland Firth, this position is subject to change as we gather additional information through the development phase for the submarine cable works. There are significant challenges with the Pentland Firth tidal streams, which are among the fastest in the world. This is supported through other marine planning applications for tidal power schemes, highlighting these areas are assessed as having high tidal streams capable of supporting large scale tidal generation schemed. The fast flowing tides are a significant challenge for cable installation and subsequent burial or stabilisation. [redacted]

4.5.5. Benefits to customers

The preferred option will facilitate the decarbonisation of homes and businesses across the Orkney islands and support the potential connection of additional generation projects at a distribution level. It will provide more reliable networks to the island group ensuring future network compliance and greater resilience. This more secure network arrangement [redacted]. The removal of reliance on DEG also delivers societal benefits with a consequential reduction in emissions. The phasing of the works from the starting point of Option 7/7A retains future optionality to achieve net zero requirements, described in sections 4.3, 4.4 and 4.5.

4.5.6. Impacted assets or programmes of work

Relevant assets affected by the proposed RIIO-ED2 works are shown in Table 37.

Asset	Related works	Delivery date
Thurso South GSP	New 66kV OHL Thurso South – John O'Groats (running at 33kV)	2028/29
South Ronaldsay Primary Substation	New 66kV OHL Burwick – South Ronaldsay (running at 33kV). Primary S/S is being created through separate LRE scheme in RIIO-ED2.	2027/28

Table 37: Assets impacted by Orkney proposals in RIIO-ED2

4.5.7. Alignment with business strategy and commitments

4.5.7.1. Alignment with licence, statutory obligations and Business Plan in RIIO-ED2

Table 38 summarises SHEPD and Ofgem positions on Orkney interventions at RIIO-ED2 Business Plan stage, and any changes made to these.

Original proposal	Ofgem position	Current proposal
Pentland Firth West Augmentation	Removed from baseline allowances and put into HOWSUM to undergo whole system analysis.	Not taken forward in RIIO-ED2.
Orkney – Hoy South Augmentation	Removed from baseline allowances and put into HOWSUM to undergo whole system analysis.	Not taken forward in RIIO-ED2. HOWSUM January 2025 proposal from Thurso – South Ronaldsay is now preferred.
Mainland Orkney – Shapinsay Replacement	Included in SHEPD CV7 baseline allowances.	Cable replaced and energised in 2024.
Hoy – Flotta Augmentation	Included in SHEPD CV7 baseline allowances.	Project on hold due to Ofgem submarine cable baseline allowance reductions.

Table 38: Summary positions on Orkney projects in RIIO-ED2 Business Plan and HOWSUM 2025 submission

4.5.7.2. Alignment with licence, statutory obligations and Business Plan for future price control periods

There are two diverging future pathways for the Orkney islands and this divergence commences at the start of RIIO-ED3. The proposed pathways will be reviewed as part of SHEPD's RIIO-ED3 Business Plan and will be influenced by the observed growth of demand and generation on the Orkney islands, including interactions at a transmission level. Our whole system analysis highlights that these works will not be required until later in the RIIO-ED3 period and, as such, future phases of works are likely to have separate funding requests in future price control submissions.

4.5.8. Project delivery and monitoring

Please refer to Section 2.7 for our general approach to project delivery and procurement. This section contains additional provisional information specific to the Orkney projects. We note that these activities have not yet commenced and are subject to ongoing refinement.

4.5.8.1. Delivery strategy

It is intended that the submarine works for this project will be delivered through our new marine installation framework on an EPCI basis. We discuss this further below.

4.5.8.2. Project delivery programme

An indicative project delivery programme for the requested RIIO-ED2 and RIIO-ED3 works are as follows:

- 2025/26 – Desktop study and site investigations.
- 2026/27 – Route survey and feasibility design and consents.
- 2027/28 – Detailed design, consents and licensing. Construction commences.
- 2028/29 – Final construction, submarine cable installation, testing and energisation.

4.5.8.3. Procurement and commercial strategy

- **Contracting approach - submarine**

See Section 2.7 for detail. [redacted]

- **Contracting approach - onshore**

See Section 2.7 for detail.

- **Procurement challenges**

To date SHEPD has not procured 66kV submarine cable or onshore assets. For the submarine cables we need to ensure that any new cable complies with international standards for type testing as well as additional internal technical approval, which we do not currently have.

[redacted]

[redacted]

[redacted]

- **Procurement activities**

Table 39 sets out the anticipated procurement activities for the Orkney project.

Package	Package description	Procurement strategy	Comments	Required completion / delivery date
1	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]

Table 39: Orkney procurement activities

- **Work carried out to date**

High level internal desktop route assessments and detailed systems analysis have been undertaken to date.

4.6. Further cost information

4.6.1. Development funding

4.6.1.1. HOWSUM development funding: Orkney RIIO-ED2 projects

The development costs for projects being implemented on Orkney in RIIO-ED2 are estimated in Table 40. Our most recent forecast analysis shows that we need to spend [redacted] on development for this project to ensure timely delivery. We can apply [redacted] of the development funding baseline allowance for these activities, which only partially covers these costs; we therefore request an additional [redacted] in this application to allow us to complete our development work for this project.

Development activity	Detail	Estimated cost	Funding status
Feasibility design	[redacted]	[redacted]	Funded through existing development funding allowance
		[redacted]	New development fund request

Table 40: HOWSUM development funding for Orkney RIIO-ED2 projects (2020/21 prices)

4.6.1.2. HOWSUM development funding: Orkney RIIO-ED3 projects

We are not requesting development funding for RIIO-ED3 projects required in the Orkney islands at this time. For Orkney specifically, we do not currently expect to start development activities for further interventions until the RIIO-ED3 period. We will include relevant development funding costs within our RIIO-ED3 Business Plan.

4.6.2. Cost efficiency

4.6.2.1. Efficiency in cost estimating

We have used all available information to provide the most accurate forecast view of costs within this submission. To achieve this, we have:

- Identified comparable completed projects to estimate costs in this submission.
- Identified comparable projects in development to estimate tender parameters.

Further detail as to how we have estimated costs is included in sections 2.6 and 4.4.1.1.

4.6.2.2. Efficiency in procurement and delivery

[redacted]

The project will also look to realise efficiencies in our onshore works, [redacted]

4.6.3. Closely Associated Indirects

As for all projects, a factor of 10.8% has been applied to the total project cost (including risk allowances) to account for the cost of CAIs and act as a proxy for the Indirects Scaler. Please see Section 2.6.5 for further information on this approach, and Section 4.1 for the specific CAI cost adjustment associated with our Orkney RIIO-ED2 interventions.

4.6.4. Key cost drivers

At this stage in the development of the projects, most cost drivers align with the general information in Section 2.6. A driver specific to this project is the use of 66kV assets, which will be a new development for SHEPD. More information on cost uncertainty is provided in the following sections.

4.6.5. Areas of ongoing uncertainty

Sections 2.6 and 2.7 provide information on areas of ongoing uncertainty which apply across our recommended projects. In this section we include in more detail on further project-specific areas of uncertainty.

4.6.5.1. Delivery

There are a significant number of risks associated with delivering large capital projects, particularly in relation to market conditions, and where operations take place offshore in harsh environmental conditions. We describe these in Section 2.7.

There are higher risks specific to the Orkney submarine cable projects located in the Pentland Firth and Scapa Flow. The project and circuit requirements dictate the need for submarine cables in the Pentland Firth and Scapa Flow areas which are subject to significantly harsher environmental conditions. These are areas of very high currents and SHEPD will complete robust feasibility studies prior to the laying of a cable in such areas.

SHEPD currently operate cables in the Pentland Firth, but these are further to the West of the proposed area and avoid the most tidal and restricted areas of the Pentland Firth. The proposed location for the new crossing is in a higher tidal current location as it is not possible to avoid this area to provide a crossing between John O'Groats and South Ronaldsay. [redacted]

4.6.5.2. Demand and generation growth

Our analysis of the Orkney network has utilised the 2023 CT DFES as the basis for our optioneering. Whilst this is a robust process that aims to capture changes in demand and generation over time, there is still uncertainty as to what extent these projections materialise, as discussed in Section 2.3. With this in mind, we have opted for a staged approach to the interventions required on the Orkney network, bringing forward the least worst regrets option for delivery in RIIO-ED2, and continuing to develop the network further in future.

4.6.6. Allowances for project risk and risk register

Our approach to quantifying risk for these projects is set out in Section 2.7.7.

4.6.6.1. Standard risk allowance

The risk register for the standard risk allowance associated with RIIO-ED2 works is detailed in Appendix 2. This provides an estimated maximum risk cost within RIIO-ED2, and associated likelihood of the risk being incurred.

For the Orkney group delivery will extend into RIIO-ED3, and not all of the risk value associated with the project will be applicable within the RIIO-ED2 period. Table 41 shows the total standard risk allowance associated with the project and the element attributed to RIIO-ED2. A number of other standard project risks will be applicable to works we propose to deliver in RIIO-ED3. Our risk assessment shows maximum standard risk is [redacted] for the entire first phase of the project to 2028/29, however only [redacted] of this is attributable to works within RIIO-ED2.

Risk allowance (£m, 2020/21 price base)	Standard risk to 2028/29	Standard risk attributed to works in RIIO-ED2
Standard risk value	[redacted]	[redacted]

Table 41: Summary of standard risk allowance for Orkney

4.6.6.2. Extraordinary risk allowance

We have engaged with Ofgem to explore the introduction of a cost adjustment mechanism in RIIO-ED2 [redacted] (see Section 2.7.7). As Ofgem is minded not to introduce a cost adjustment mechanism [redacted], we have included an associated allowance request in this submission. [redacted]

Extraordinary risk allowance (£m, 2020/21 price base)	Estimated cost
Orkney RIIO-ED2 execution stage costs	[redacted]
Application of extraordinary risk allowance provision	[redacted]
Orkney extraordinary risk allowance	[redacted]

Table 42: Extraordinary risk allowance for Orkney

4.7. Stakeholder engagement

In this section we summarise stakeholder engagement specific to the Orkney interventions. Please also see Section 2.2, the Orkney Thurso South GSP SDP and Appendix 4A – Orkney EJP.

4.7.1. Recent engagement

We have continued to engage with stakeholders on the future energy needs for the Orkney islands network. This includes engagement by and with specialist consultant Regen aimed at informing our projections of future demand and generation.

4.7.1.1. Webinar – February 2024

49 RIIO-2 Re-opener: Scottish and Southern Electricity Network's 2024 Skye-Uist Project | Ofgem

We ran a specific webinar focused on the Orkney islands on 29th February 2024. 18 stakeholders attended this event with their feedback informing our overall approach and the material within this application. We provided background on the local network, the drivers for change, and our approach to developing options. We also covered the development of our approach to island resilience as well as an overview of the DFES projections for the area.

Stakeholder feedback was:

- Grid reinforcement is seen as key to facilitating local net zero ambition.
- There is a need to understand the interface with the proposed transmission link and what this means for generation customers.
- There is a strong appetite for community-owned generation in Orkney.
- Early sight of future generation and demand drivers is key.
- The load drivers identified for Orkney were acceptable, but the potential of maritime decarbonisation needs to be considered.

4.7.1.2. Webinar – September 2024

On 6th September 2024 we held a webinar to provide an update to stakeholders on the whole system analysis being undertaken through HOWSUM and to seek their views on the drafting of the Orkney – Thurso South GSP SDP. Seven stakeholders attended this event with their feedback helping to shape our proposals for this submission, as well as informing our approach to the SDP.

- Growing house building on the islands was highlighted as a key consideration.
- There remains a strong appetite for community energy projects in Orkney.
- Stakeholders are keen to be kept informed as the process develops, with webinars the preferred method of communication.
- Research and innovation organisations in Orkney are keen to be seen as leading the way on net zero/energy innovation initiatives.
- There is currently a large untapped potential for wave and tidal energy in Orkney that should be considered.
- Concern that the DFES projections for Orkney do not capture local ambition with local stakeholders keen to feedback alternative suggestions.

4.7.1.3. Roundtable – December 2024

On 18th December 2024 we held an online roundtable session to provide stakeholders with an overview of the optioneering process we had worked through as part of HOWSUM and present the preferred option that had emerged from that process. Feedback from the nine stakeholders in attendance helped refine this submission and highlighted points for further collaboration on the continual refreshment of the SDP.

- Communities in Orkney want to continue to be involved in the development of DFES for the area. Proposals are to be submitted to SHEPD for formal community involvement.
- Ambitious plans for decarbonisation of the Orkney economy by 2030 were noted in the context of a 2050 plan for the network.
- Futureproofing shorter term works by including proprietary works for proposed medium- and longer-term interventions should be considered.

- Stakeholders pleased to see provision of additional submarine cable capacity to the islands but keen to continue to be involved in the refinement of plans.

4.7.1.4. Bilateral engagement

In addition to the SHEPD bilaterals listed below, Regen has also engaged bilaterally with stakeholders in the development of their insights report.[50]

- Scotch Whisky Association
  - 24th October 2023: Discussion on the range of decarbonisation strategies employed by distilleries both on islands and the mainland.
- Orkney Islands Council
  - Regular engagement throughout 2023 and 2024 providing ongoing updates on the HOWSUM process, gathering insights to inform the DFES and providing targeted engagement to ensure synergies with local development plans.
- Community Energy Scotland
  - 27th May 2024: Meeting with Carbon Neutral Islands project officers to provide an update on HOWSUM work and signpost to upcoming consultations.
- SSEN Transmission
  - 1st December 2023: We provided an overview of Regen's insights work and asked for feedback and input.
  - 16th August 2024: Update on shortlisted options identified from our whole system analysis and discussion on operational implications.
  - 8th November 2024: Update on shortlisted options and alignment with RIIO-T3 planning.
  - 9th December 2024: Detailed discussion on Orkney pathways.
- Highlands and Islands Enterprise (HIE)
  - 26th June 2024: Overview of HOWSUM process and plans for the Orkney Islands to allow HIE to engage their clients in the area.
- Orkney Renewable Energy Forum (OREF)
  - 13th June 2024: In person meeting in Stromness with representatives of OREF (EMEC, Aquatera, Community Energy Scotland, Orkney Islands Council, Heriot-Watt University) to talk through load drivers for Orkney interventions and early optioneering. Discussion around OREF potentially providing additional information to supplement the DFES projections.
- Islands Centre for Net Zero
  - Regular bi-monthly meetings through 2024 to provide updates and obtain feedback on progress with HOWSUM planning work.

4.7.1.5. SDP engagement

50 Orkney Islands Net Zero Load Growth Evidence Summary Study

Our draft Thurso South Grid Supply Point SDP consultation was published on 7th November 2024.[51] The consultation closed on 10th December 2024, with four formal responses received. These responses were assessed using the RICE methodology with feedback summarised below.

- Local communities are keen to input into the development of the DFES projections to help SHEPD better understand the future energy requirements of the Orkney islands.
- Stakeholders are keen to better understand the impact of the proposed transmission link to Orkney and its interface with the distribution network, particularly in relation to the pipeline of onshore and offshore wind projects.
- Further understanding of the impact that any additional submarine cable capacity will have on alleviating constraints on existing ANM customers was requested.

These responses will be addressed in the finalised SDP publication, as well as informing our engagement on the annual update to the plan. Stakeholders will also receive a direct response to their individual consultation feedback. Our finalised SDP will be published on our website.[52]

4.7.2. Stakeholder engagement impacts

Table 43 summarises how we have considered feedback received to date.

STAKEHOLDERS SAID	WE DID
Request further clarity on our plans and need for continued engagement.	We have offered additional opportunities to engage through dedicated bilateral discussions and held webinars to update on our progress. We held further engagement through 2024 ahead of this submission.
We need to consider the community energy pipeline.	We worked with Regen to holder deeper engagement with local communities and industries to understand future requirements and opportunities, and ensured this information was reflected in our DFES.
We need to consider demand for additional housing provision in the area.	We have engaged with Orkney Islands Council on their local housing strategies and plans and have received more granular responses on local housing numbers through our DFES engagement process.
There is concern that the DFES projections do not capture the level of ambition regarding decarbonisation in Orkney and local organisations were keen to provide supplementary evidence.	We have invited stakeholders in Orkney to feedback information and data that they feel can supplement/contradict the DFES projections. To date, no responses have been received.
We need to better understand the implication of wider SSEN (Transmission and Distribution) works on Orkney.	We have regularly engaged with SSEN Transmission colleagues on their plans for Orkney and our proposed solutions consider the transmission projects for the Islands.
The future impact of maritime decarbonisation needs to be understood.	The innovation project SeaChange[53] is exploring the pathways to decarbonisation for ports and the ripple effects this will have on our network. We will incorporate the results of this into our Thurso South SDP when they become available mid-2025.

Table 43: Acting on stakeholder feedback under the HOWSUM workstream

51 Survey Details | Thurso South Grid Supply Point Strategic Development Plan Consultation

52 Publications & Reports - SSEN

53 SSEN's nature and shipping innovation projects win £1m in new development funding - SSEN

4.8. Conclusion: Orkney

We have identified two potential pathways to 2050 for the network to the Orkney islands.

1. **Demand Resilience Pathway** – Pathway based on demand resilience, where 66kV submarine links are installed to the Orkney islands upgrading the existing 33kV PFE and PFW circuit to run at 66kV (Option 7). Option 7 initially installs a new 66kV submarine cable between Thurso South and South Ronaldsay substation during RIIO-ED2.
2. **Generation Export Pathway** - Pathway based on generation export, where an additional transmission circuit is supported by 33kV reinforcement (Option 2). This pathway will also require the potential use of flexibility ahead of the second transmission link.

Onshore connections to substations will support each route.

The current optimum pathway recommended in this submission is a variant of the Demand Resilience Pathway (Option 7A, shown in Figure 23). The specific recommendations required to be undertaken in RIIO-ED3 and beyond will be reviewed again in preparation for the RIIO-ED3 price control. Option 7A has been chosen because it is:

1. The most cost-effective option with the most favourable NPV of the options that allow for the emergence of both identified pathways.
2. Ensures future resilience for the Orkney islands.
3. Meets future demand and generation requirements.
4. Provides a credible route to facilitate decarbonisation of our DEG fleet.
5. Maintains future optionality for the network.

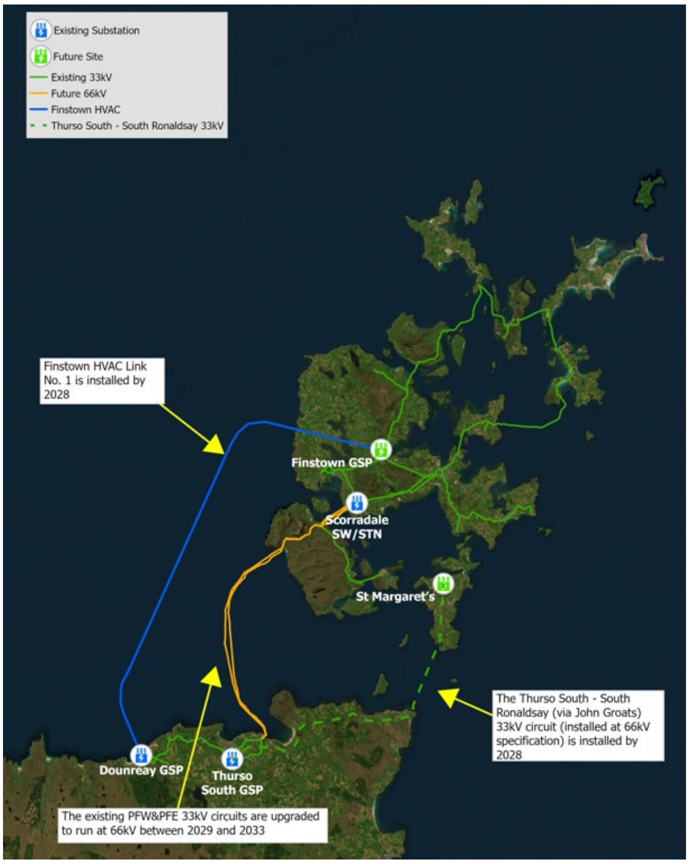

Figure 23: 2050 strategic plan for Orkney – Hybrid Solution (Option 7A)

Summary of adjustment request – Orkney

Adjustment summary (£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Total adjustment for Orkney	-	-	-	[redacted]	[redacted]	[redacted]

Table 44: Orkney allowance adjustment summary

5. INNER HEBRIDES: MULL, COLL AND TIREE

Our longer-term proposals for the Mull, Coll and Tiree group are to install two additional submarine cables during RIIO-ED3. The first would be a [redacted] 33kV cable between Tullich switching station and Mull. The second cable would be [redacted] cable supplying Coll from Mull. We would also be replacing Tiree Power Station with a zero-carbon energy source, which could be a third-party solution.

We are not requesting funding for project delivery works in RIIO-ED2, but we are seeking additional development funding to progress early-stage activities associated with our recommended RIIO-ED3 interventions, to ensure their timely progression. This is noted in Table 45.

In this chapter we provide a summary of the analysis and stakeholder engagement we have carried out to develop our recommendations to intervene on the network in RIIO-ED3. We present this in a more condensed format than in previous chapters., recognising that our recommendations will be refined over RIIO-ED2, taking account of information gathered through associated development activities, to be submitted as part of our RIIO-ED3 Business Plan. Further information is available in our 2050 SDP.[54]

Adjustment summary (£m, 2020/21 price base)	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**Total**
Total adjustment for Inner Hebrides: Mull-Tiree	-	-	-	-	[redacted]	[redacted]

Table 45: Inner Hebrides: Mull-Coll-Tiree allowance adjustment summary

5.1. Allowance adjustment

Table 46 sets out the allowance adjustment sought for Inner Hebrides: Mull – Coll – Tiree in this application.

Adjustment summary (£m, 2020/21 price base)	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**Total**
Total Inner Hebrides Mull-Tiree Forecast[1]	-	-	**-**	-	[redacted]	[redacted]
Delivery costs[2]	-	-	-	-	[redacted]	[redacted]
Development costs (pre-funded)[3]					[redacted]	[redacted]
Development costs (request)[4]	-	-	-	-	[redacted]	[redacted]
Standard risk allowance[5]	-	-	-	-	[redacted]	[redacted]
Extraordinary risk allowance[6]	-	-	-	-	[redacted]	[redacted]
CAIs[7]	-	-	-	-	[redacted]	[redacted]
Total adjustment[8]	**-**	**-**	**-**	**-**	[redacted]	[redacted]

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1. 'Total forecast' means all project costs (including development costs, capital and operating costs, risk and CAIs) before the deduction of any applicable HOWSUM development funding baseline allowance.
2. 'Delivery costs' are project costs before the addition of development, risk and CAI costs. These are estimated costs provided prior to carrying detailed procurement and delivery assessment processes.
3. 'Development costs (pre-funded)' is the amount of development costs which has been covered by the existing HOWSUM development funding baseline allowance of £20.6m. See Section 2.6.6.
4. 'Development costs (request)' is the amount of additional development funding required to progress the relevant island interventions, which the HOWSUM development funding baseline allowance does not cover.
5. The standard risk allowance covers foreseeable and fairly well understood types of risks. See Section 2.7.7 and our risk registers for more detail.
6. The extraordinary risk allowance covers [redacted], after addition of CAIs. See Section 2.7.7.
7. CAI costs are calculated as 10.8% of total project costs, after addition of project risk allowances. See Section 2.6.5.
8. Total adjustment = (Total Inner Hebrides Mull-Tiree forecast – Development costs (pre-funded))

Table 46 Inner Hebrides: Mull – Coll - Tiree allowance adjustment

5.2. Background to investment

The islands of Mull, Coll and Tiree are supplied from Taynuilt GSP on mainland Scotland by a mixture of OHL, UG cable and various submarine cables.

Coll and Tiree are currently supplied via a single 11kV submarine cable from Dervaig Primary substation on Mull with a subsequent 11kV cable between Coll and Tiree. The islands are supported [redacted] by Tiree Power Station [redacted]. Analysis of the CT DFES indicates that the combined demand of Coll and Tiree will reach [redacted] MW by 2050.

The island group is supplied from Taynuilt to Mull via [redacted] submarine cable (two circuits) which run from the mainland to Kerrera and then from Kerrera to Mull. There is a further submarine cable which runs from Lochaline from Mull to the Morvern peninsula, [redacted]

Our analysis of this section of the Inner Hebrides network identifies network needs for enhanced capacity to meet demand and ensure security of supply, and proposes investment in the network to both meet our net zero commitments and work towards compliance with our Islands Resilience Policy (2.4.1.2).

5.3. Needs case and optioneering

5.3.1. Primary and secondary investment drivers

The primary investment driver for completing this work is increased demand based on our 2023 DFES projections. The existing Mull archipelago network will not support projected demands out to 2050 without additional network investment. Our analysis indicates the first of several interventions will be required at the beginning of RIIO-ED3.

We have also identified and assessed longer term drivers, both in the development of our longer-term strategy and in the sizing of cables and other circuit elements in this application. These are:

1. **Future generation requirements on the islands**: We have investigated the future distribution connected generation estimates, ensuring cable sizing will allow the forecast import and export of power between the islands and the mainland.

2. **Future resilience needs of the islands**: Currently our DEG fleet provides back-up supplies for the islands of Coll and Tiree, [redacted]. However, these generators are aging and are a significant source of emissions. We have also reviewed the network in line with our DEG strategy and Islands Resilience Policy. The review indicates that further interventions will be required [redacted].

In addition to these drivers there are a number of other factors we have taken into account including the use of flexibility as an alternative to traditional reinforcement. See sections 2.2, 2.3 and 2.4 for more information on our identification of needs and drivers for these interventions.

5.3.2. Methodology for assessing options and selection of the preferred option

We have identified two separate schemes that should be taken forward to address the needs case for the archipelago. These are a new 33kV connection from the mainland to Mull (Scheme A), and a reinforcement of the existing network to the islands of Coll and Tiree (Scheme B), illustrated in Figure 24.

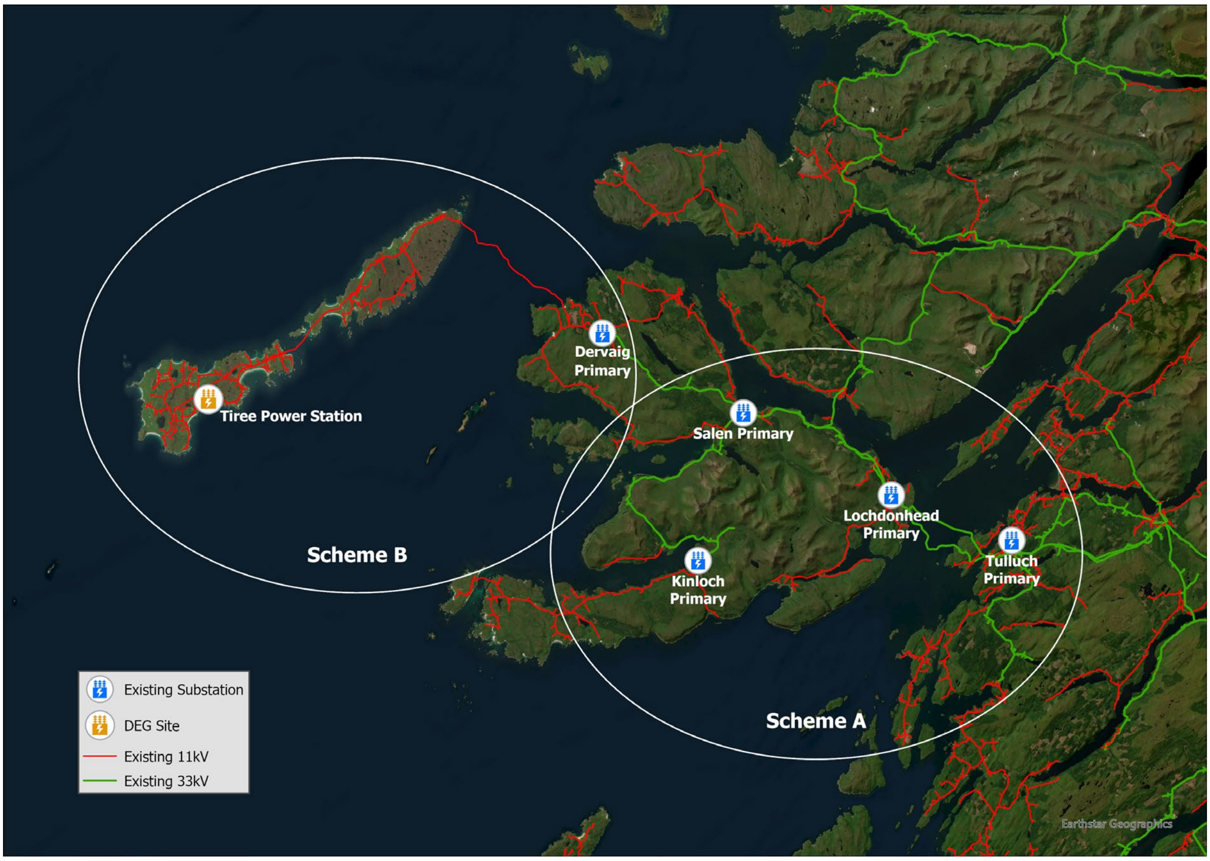

Figure 24: Scheme A: Mainland-Mull and Scheme B: Coll-Tiree

We review these in turn in the following sections.

5.3.1. Whole System opportunities

We have consciously identified, assessed and selected options through a whole system lens to take account of energy requirements in 2050, as well as the interactions with Transmission, embedded generation and potential future energy sources and demands. The solutions recommended in this submission are selected based on their ability to form part of a long-term, whole system solution for the Mull archipelago. Stakeholders have repeatedly advised us that Tiree has the highest solar irradiance of any island in GB and would therefore be a good place for solar power investment. We believe the proposed additional 11kV cable can help facilitate this opportunity.

5.3.2. Interactions with transmission works

It is critical to ensure that a whole system view is taken of the future requirements for this area. We have engaged with SSEN Transmission to understand future planned transmission works and how they may impact our developments. We have assessed that there is limited interaction with the transmission network in this area at this stage.

5.3.3. Optioneering and cost benefit analysis

5.3.3.1. Scheme A: Mainland - Mull

The options for the connection of the mainland to Mull are summarised in Table 47. These options have been assessed to ensure they are technically feasible and are fed into CBA for further assessment.

Option	Summary
A1	Install 1 new 33kV Tullich - Lochdonhead circuit by 2030 (direct mainland - Mull) and replace the [redacted] existing <20MW rated submarine cables between the Mainland, Kerrera and Mull by 2040.
A2	Install 1 new 33kV Tullich - Lochdonhead circuit by 2030 (island hopping - no HDD from Mainland to Kerrera) and replace the [redacted] existing <20MW rated submarine cables between the Mainland, Kerrera and Mull by 2040.
A3	Install 1 new 33kV Tullich - Lochdonhead circuit by 2030 (island hopping - end-to-end HDD from Mainland to Kerrera) and replace the [redacted] existing <20MW rated submarine cables between the Mainland, Kerrera and Mull by 2040.

Table 47: Options considered for mainland - Mull

5.3.3.2. Deterministic CBA: Mainland - Mull

We completed a deterministic CBA for each of the technically feasible options developed in the optioneering process. The results for these options are summarised in Table 48, which shows that Option A1 is the optimum option.

Option	10 years	20 years	30 years	45 years	Whole life (55 years)
A1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 48: Deterministic CBA results for Mainland - Mull - NPV at different intervals (£m, 2020/21 prices)

5.3.3.3. Scheme B: Coll and Tiree

The options for reinforcing the existing network to the islands of Coll and Tiree are summarised in Table 49. These options have been assessed to ensure they are technically feasible, and the options that fulfil the criteria have been fed into CBA for further assessment.

Option name	Summary
B1a – Replace Tiree DEG	Replace Tiree DEG by 2033 [redacted]
B1b – Replace Tiree DEG and 11kV submarine cable	Replace DEG by 2033 [redacted] Install a new 11kV submarine cable between Dervaig and Coll [redacted] by 2033.
B2 – 33kV Salen-Calgary-Tiree circuit and 33/11kV Tiree primary substation	Remove reliance on DEG by 2033. Install a new 33kV Salen-Calgary-Tiree circuit by 2033, including a new 33kV board at Salen and a submarine cable from Calgary Beach to Tiree. New 33/11kV Tiree primary substation by 2033.
B3 – 33kV Balmeanach-Tiree circuit and 33/11kV Tiree primary substation	Remove reliance on DEG by 2033. Install new 33kV Balmeanach - Tiree circuit by 2033. New 33/11kV Tiree primary substation by 2033.

Table 49: Options considered for Coll-Tiree

5.3.3.4. Deterministic CBA: Coll and Tiree

We carried out deterministic CBA on each of the technically feasible options developed in the optioneering process. The CBA results for these options are summarised in Table 50, which shows that Option B1a is the optimum option.

Option	10 years	20 years	30 years	45 years	Whole life (55 years)
B1a	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
B1b	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
B2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
B3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 50: Deterministic CBA results for Coll - Tiree - NPV at different intervals (£m, 2020/21 prices)

The deterministic CBA calculates Option B1a as the optimum NPV.

5.3.3.5. Strategic CBA: Coll and Tiree

Options B1a, B1b and B2 have been assessed further using the Strategic CBA. Due to the differences in the asset solutions seen in these three options for Coll/Tiree, there is a unique use-case for the Strategic CBA to compare the generation benefits associated with each. In particular, to compare the additional benefits which could be enabled through an additional submarine cable versus a solution involving a zero carbon energy resource. Option B1a and Option B2 were compared against five different delivery year options for Option B1b. The Strategic CBA has been used to investigate the impact of these options under the Consumer Transformation (CT), Leading the Way (LW), and System Transformation (ST) DFES scenarios. For further information on the Strategic CBA, see Section 2.3.4.1.

The results following this assessment are summarised in Figure 25. This shows the breakdown of the components included in the NPV to 2050 for each option.

[redacted]

Figure 25: Strategic CBA results for Coll-Tiree network intervention options

The CBA categories in Figure 25 can be interpreted as follows:

- SHEPD/Third Party costs (blue areas): This consists of capex, opex and DEG costs associated with each option as in line with the Ofgem Deterministic CBA.
- Societal costs / benefits (yellow areas): This consists of costs or benefits to society in general. In this case, this refers to the CO_2 emissions from DEG, and reduced CO_2 emissions and costs associated with reduced network losses.
- Customer costs / benefits (green areas): This category includes benefits associated with enabling customer connections. For Tiree and Coll, benefit from enabling generation connections has been assigned to the submarine cable options (Options B1b and B2) with a reduced benefit seen in Option B1b due to the capacity of the cable.

Highlights from the Strategic CBA results:

- Under the CT scenario, the highest NPV is seen in Option B1b with delivery in 2031. This result is primarily driven by the balance between the increase in customer benefits due to enabling generation connections more quickly (green bar) and an increase in capex costs if the work is brought forward. There is also a benefit seen from reduced CO_2 emissions from decommissioning the DEG earlier and from savings due to reduced losses.
- When the System Transformation (ST) and LW scenarios are also considered, Option B1b with delivery in 2033 offers the least worst regret.

5.3.4. Preferred options

5.3.4.1. Preferred option: Mainland - Mull

Based on our initial deliverability assessment and CBA, the preferred option for the mainland to Mull reinforcement is Option A1, where we look to install a new 33kV route from Tullich 33kV switching station on the mainland to Lochdonhead Primary substation on Mull. The proposed option can be seen Figure 26.

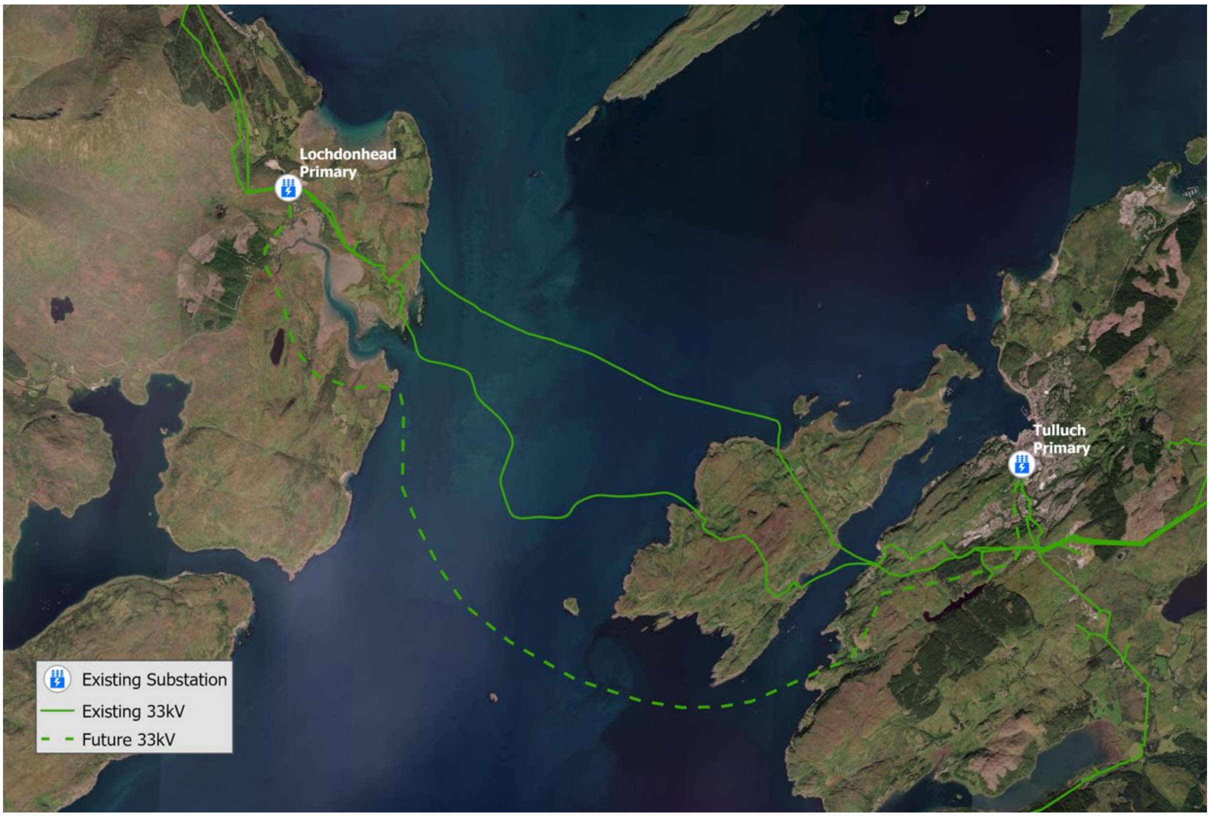

Figure 26: Indicative 2050 strategic plan for mainland Scotland - Mull (Option A1)

5.3.4.2. Preferred option: Coll and Tiree

Taking account of the relevant wider costs and benefits assessed under the Strategic CBA, the preferred option for reinforcing the existing network to the islands of Coll and Tiree is Option B1b. This option proposes to:

- Replace Tiree DEG with a zero-carbon energy source (e.g. battery) that could provide peak demand management [redacted], and
- Install an additional 11kV submarine cable between Dervaig and Coll [redacted].

Both elements are currently required for completion by the end of 2032/33. A map detailing the preferred option is shown in Figure 27.

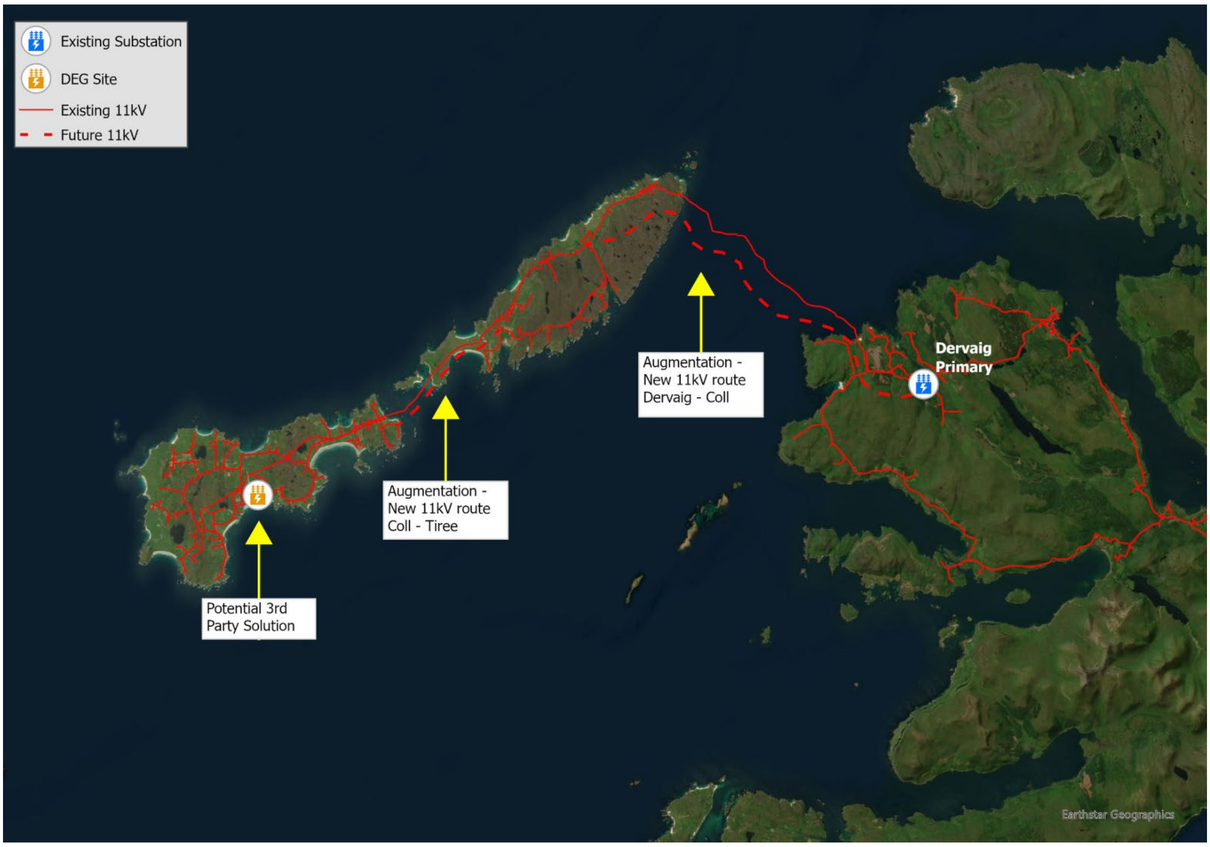

Figure 27: Indicative 2050 strategic plan for Coll and Tiree (Option B1b)

5.3.5. Timing of investment and rationale for phasing interventions

Our analysis of the greater Mull network indicates that no additional works are required during RIIO-ED2. We will however start development works on the proposed cables which are due early in RIIO-ED3 and mature our thinking on the Tiree DEG replacement. These works will remain under review as part of our enduring strategic planning process.

5.4. Further cost information

5.4.1. Development funding

5.4.1.1. HOWSUM development funding: Mull, Coll, Tiree RIIO-ED2 projects

As we are not delivering projects in RIIO-ED2 for this island group, we do not require development funding for RIIO-ED2 projects.

5.4.1.2. HOWSUM development funding: Mull, Coll, Tiree RIIO-ED3 projects

In order to deliver the recommended works required in RIIO-ED3 for this island group, we need to start project development in RIIO-ED2. Given the uncertainty around network requirements in RIIO-ED2 we did not include a funding request at the RIIO-ED2 Business Plan stage. We have forecast additional development funding requirements in Table 51 and have included these in our adjustment request for this submission. These costs relate to the new route between the Mainland and Mull section of our long term plans, and all other works related to Coll and Tiree will be captured in our RIIO-ED3 Business Plan submission.

We will also be using the requested additional development funding to further consider and progress the potential for alternative / third party solutions to DEG, to support demand management on Coll and Tiree.

Development activity	Detail	Estimated cost	Funding status
Mainland – Mull design feasibility assessments and Tiree DEG assessment	[redacted]	[redacted]	Funded through existing development funding allowance
		[redacted]	New development fund request

Table 51: HOWSUM development funding for Inner Hebrides: Mull – Coll - Tiree RIIO-ED3 projects (2020/21 prices)

5.4.2. Cost efficiency

[redacted]

5.4.3. Areas of ongoing uncertainty

The replacement of Tiree DEG is an important consideration [redacted]. We need to understand more about the costs and options that apply. This includes understanding the viability of alternative and third-party solutions that would be able to provide a reliable source of power for long periods of time if needed.

5.4.4. Allowances for project risk and risk register

Our approach to quantifying risk for these projects is set out in Section 2.7.7.

5.4.4.1. Standard risk allowance

The associated risk register for the standard risk allowance is detailed in Appendix 2. This provides an estimated maximum cost of the risk and associated likelihood of the risk being incurred in carrying out the development activities within RIIO-ED2 to be able to deliver the recommended interventions between the Mainland and Mull in early RIIO-ED3. A standard risk allowance of [redacted] for Inner Hebrides Mull-Coll-Tiree has been estimated and is included within our adjustment request.

Risk allowance	Standard risk attributed to development works in RIIO-ED2
Standard risk value	[redacted]

Table 52: Summary of standard risk allowance Inner Hebrides: Mull - Coll - Tiree

5.4.4.2. Extraordinary risk allowance

Given that we do not propose to deliver execution works in RIIO-ED2, we do not currently seek any extraordinary risk allowance.

5.4.5. Future work being assessed under HOWSUM mechanism

All proposals identified in our current strategic plan for Mull, Coll and Tiree will undergo further assessment prior to regulatory submission as part of our RIIO-ED3 Business Plan. This may alter the nature and/or timing of any proposal.

5.5. Stakeholder engagement

In this section we summarise stakeholder engagement we have progressed which is specific to the Mull, Coll and Tiree archipelago. Please also see Section 2.2.

5.5.1. Recent engagement

We have continued to engage with stakeholders on the future energy needs for the Mull, Coll and Tiree network area. This includes Regen engagement to understand future energy insights.

5.5.1.1. Webinar - February 2024

We ran a specific webinar focused on the Inner Hebrides on 29th February 2024. Sixteen stakeholders attended this event with their feedback informing our overall approach and the material within this application. The event provided background on the local network, the drivers for change, and our approach to developing options. We also covered the development of our Islands Resilience Policy as well as an overview of the DFES projections for the area.

Stakeholder feedback was:

- Grid reinforcement is seen as key to facilitating local net zero ambition
- Electrification seen as a potential solution to fossil fuel heat decarbonisation so total energy demand needs to be considered, not just electric
- There is a strong appetite for community owned generation in the Inner Hebrides
- Need to be aware of local industrial clusters with significant net zero ambition which could rely on electrification. E.g. distilleries.
- Feedback was mixed on our islands resilience policy. It was felt that it needed to be further informed by an increased understanding of potential local load growth

5.5.1.2. Webinar – September 2024

On 11th September 2024 we held a webinar to provide an update to stakeholders on the whole system analysis being undertaken through HOWSUM and to seek their views on the drafting of our Taynuilt GSP Strategic Development Plan. Seven stakeholders attended this event with their feedback helping to shape our proposals for the January 2025 submission, as well as informing our approach to the Strategic Development Plan.

- Stakeholders were in general agreement that our strategic development planning process was fit for purpose
- Local energy groups and generators are keen to collaborate with SHEPD on achieving network resilience and managing demand. There was particular interest in provision of flexibility services
- Growth in house building on the islands was highlighted as a key consideration
- There remains a strong appetite for community energy projects with both solar and run of river hydro highlighted as key considerations.
- Stakeholders are keen to be kept informed as the process develops, with webinars the preferred method of communication

5.5.1.3. Roundtable – December 2024

On 17th December 2024 we held an online roundtable session to provide stakeholders with an overview of the optioneering process we had worked through as part of HOWSUM and present the preferred option that had emerged from that process. Feedback from the five stakeholders in attendance has helped with refining the January 2025 submission and has also raised points for further collaboration through our strategic development planning process.

- Stakeholders keen to understand if additional, strategically planned, generation and storage assets on the islands could negate the need for additional submarine cabling to the islands.
- Stakeholders are keen to understand what the plans mean in practice for connections on the island.
- Further clarification was sought, and provided, on the timescales for any proposed interventions. This included which works fall in RIIO-ED2 and what is RIIO-ED3 and beyond.
- Strong appetite for community renewable energy projects continues to be highlighted as a local priority.

5.5.1.4. Bilateral engagement

In addition to the SHEPD bilaterals listed below Regen have also engaged bilaterally in the development of their energy insights.

- Scotch Whisky Association
    - 24th October 2023: Discussion on the range of decarbonisation strategies employed by distilleries both on islands and the mainland.
- Argyll and Bute Council
    - Regular engagement throughout 2023 and 2024 providing ongoing updates on the HOWSUM process, gathering insights to inform the DFES and providing targeted engagement to ensure synergies with local development plans.
- Community Energy Scotland

- 27th May 2024: Meeting with Carbon Neutral Islands project officers to provide an update on HOWSUM work and signpost to upcoming consultations.

- SSEN Transmission
    - 1st December 2023: We provided an overview of Regen's insights work and asked for their feedback and input.
    - 16th August 2024: Update on shortlisted options identified via the HOWSUM process and discussion on operational implications.
- Highlands and Islands Enterprise (HIE)
    - 26th June 2024: Overview of HOWSUM process and plans for the Inner Hebrides to allow HIE to engage their clients in the Inner Hebrides.

5.5.1.5. SDP engagement

Our draft Taynuilt GSP Strategic Development plan was published for consultation on 22nd November 2024. The consultation closed on 20th December 2024, with two formal responses received. These responses were assessed using the RICE methodology with feedback summarised below.

- Local communities are keen to continue to be involved in the refinement of the DFES projections, particularly when capturing some of the nuances of remote/rural and island communities.
- The criticality of improved network capacity for the economic development of remote/rural communities was highlighted as a key local priority.
- The need for continued alignment of SHEPD network planning with the local council's Local Development Planning process was called out.

These responses will be addressed in the finalised Strategic Development Plan publication, as well as informing our engagement on the annual update to the plan. Stakeholders will also receive a direct response to their individual consultation feedback. Our finalised SDP will be published on our website.[55]

5.5.1.6. Stakeholder engagement impact

Table 53 sets out key feedback and our responses to date.

STAKEHOLDERS SAID	WE DID
Stakeholders need further clarity on our plans and there is a need for continued engagement.	We have offered additional opportunities to engage with us through dedicated bilateral discussions and held webinars to update stakeholders on our progress. We held further engagement through 2024 ahead of our January 2025 re-opener application.
We need to consider the community energy pipeline	We worked with Regen to more greatly engage with local communities and industries to understand future requirements and opportunities, and ensured this information was reflected in our Distribution Future Energy Scenarios.
We need to consider demand for additional housing provision in the area	We have engaged with Argyll and Bute Council on their local housing strategies and plans and have received more granular responses on local housing numbers through our DFES engagement process.

55 Publications & Reports - SSEN

STAKEHOLDERS SAID	WE DID
There is appetite for local participation in provision of flexibility services for island networks	We published a request for information in September 2024, looking to further gauge the appetite and availability of potential flexibility providers in the Scottish Islands.

Table 53: Acting on stakeholder feedback under the HOWSUM workstream

5.6. Conclusion - Inner Hebrides: Mull, Coll and Tiree

There are no RIIO-ED2 projects proposed in this island group, but within RIIO-ED2 we will be progressing the development of interventions required to be delivered in RIIO-ED3. We are therefore requesting additional HOWSUM development funding to undertake this activity. We also seek funding of a standard risk allowance driven by these development activities.

Our RIIO-ED3 recommendations consist of:

- An additional 33kV circuit between Tullich switching station on the mainland directly to Lochdonhead on Mull.
- An additional 11kV circuit between Dervaig on Mull and Coll.
- Replacement of Tiree DEG (potentially through a third-party solution).

These recommendations, set out in Figure 28, will be refined in the preparation of our RIIO-ED3 Business Plan submission.

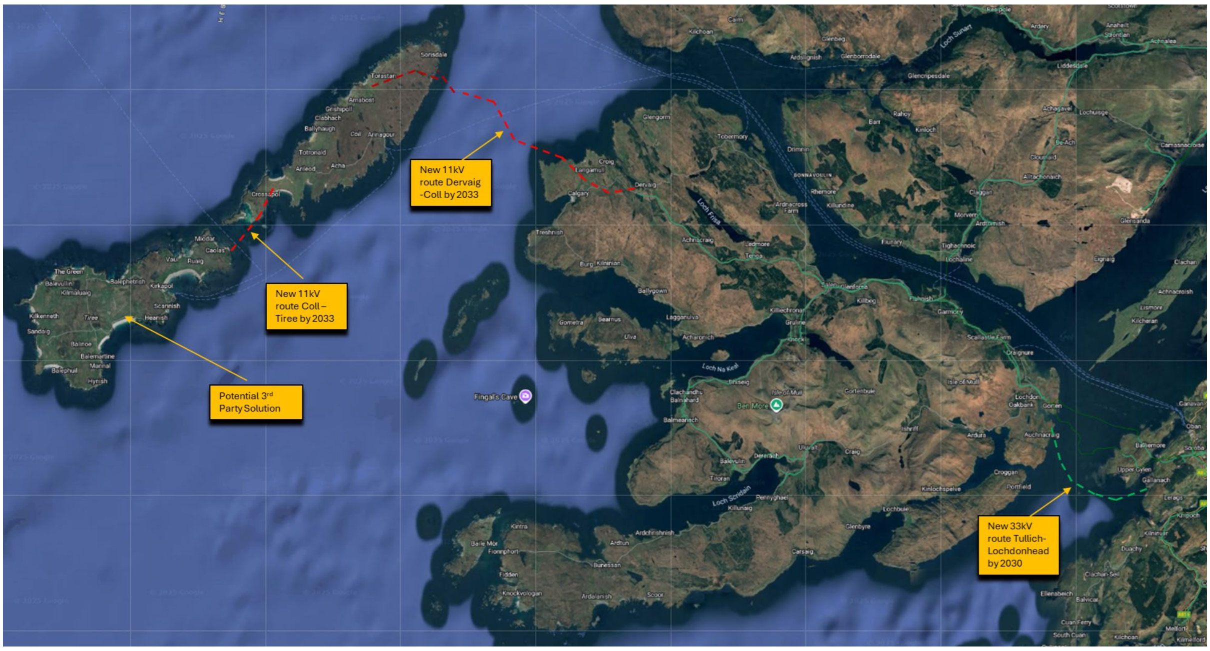

Figure 28: Indicative 2050 strategic plan for mainland Scotland to Mull, Mull to Coll and Coll to Tiree

Summary of adjustment request - Inner Hebrides: Mull, Coll and Tiree

Adjustment summary (£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Total adjustment for Inner Hebrides – Mull-Coll-Tiree	-	-	-	-	[redacted]	[redacted]

Table 54: Inner Hebrides: Mull, Coll and Tiree allowance adjustment summary

6. OUTER HEBRIDES AND SKYE

The detailed proposals and justification for the Outer Hebrides interventions were set out in our HOWSUM January 2024 application and July 2024 Skye – South Uist addendum.[56] There have been no substantive changes to our 2050 strategic plan for the Outer Hebrides set out in these documents, which are summarised for reference in this section (see Figure 29), other than an optimisation of timings of interventions to align with our commitment to remove reliance on DEG by the end of RIIO-ED3 (see Table 55), which will be reflected in our RIIO-ED3 Business Plan.

In this submission we request additional funding to commence development work on the proposed second Ardmore – Harris 33kV cable, to support the timeline to implement it by 2032. [redacted] We are seeking additional funding for DEG operations (and potentially some use of flexibility) during these periods.

We will review our strategic plan for the Outer Hebrides in 2025 as part of our Strategic Planning Development Process and will confirm additional requirements as part of our RIIO-ED3 Business Plan. This review will also include further updates on long-term benefits of the Ardmore – Loch Pooltiel 33kV optimisation loop, introduced primarily to mitigate delays in delivering the Dunvegan – Loch Carnan circuit. Our 2050 SDP will be published on our website for consultation in spring 2025.[57]

56 Whole system energy solutions for the Scottish islands - SSEN

57 DSO Consultation Library - SSEN

Figure 29: 2050 strategic plan for Outer Hebrides and Skye

Table 55 summarises the timings needed for each of the proposed investments. A staged approach allows us to modify and update our plans in accordance with stakeholder needs. To this end we will be reviewing our programme through 2025 to check the continued validity of both the proposals and the timing of interventions.

Project element	Key outputs	Forecast delivery dates[1]
Skye – Uist – Harris	New 33kV submarine cable and 33kV OHL Skye – Uist, and onshore substation upgrades Dunvegan – Loch Carnan	Forecast delivery 2027/2028 (submarine cable element 2026)[2]
	New 33kV submarine cable and onshore substation upgrades – Ardmore-Loch Pooltiel	Forecast delivery 2026/27
	New 33kV submarine cable Skye – Harris	*Forecast delivery 2031/32*
	New 33kV submarine cable and overhead line Harris – Uist	*Forecast delivery 2032/33*[3]

[1] Delivery dates are estimated, not wholly within our control and will be refined as projects are further developed.
[2] [redacted] Dunvegan – Loch Pooltiel OHL anticipated to be delivered in 2028. We are in parallel progressing the Ardmore – Loch Pooltiel optimisation that is planned to be used to accelerate the programme to delivery in 2026.
[3] Delivery of this asset has been brought forward from 2035 as originally proposed in the HOWSUM July 2024 application, to facilitate removal of reliance on DEG by the end of RIIO-ED3.

Table 55: Expected key outputs and years of delivery for Outer Hebrides and Skye

6.1. Allowance adjustment

Table 55 sets out the allowance adjustment sought for the Outer Hebrides and Skye in this submission.

Adjustment summary (£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Total Outer Hebrides and Skye Forecast[1]	**-**	**-**	[redacted]	[redacted]	[redacted]	[redacted]
Delivery costs[2]	-	-	-	-	-	-
Development costs (pre-funded)[3]			-	-	-	-
Development costs (request)[4]	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Standard risk allowance[5]	-	-	-	-	[redacted]	[redacted]
Extraordinary risk allowance[6]	-	-	-	-	-	-
CAIs[7]	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Additional outage costs[8]			[redacted]	[redacted]	[redacted]	[redacted]
Total adjustment[9]	**-**	**-**	[redacted]	[redacted]	[redacted]	[redacted]

1. 'Total forecast' means all project costs (including development costs, capital and operating costs, risk and CAIs) before the deduction of any applicable HOWSUM development funding baseline allowance.
2. 'Delivery costs' are project costs before the addition of development, risk and CAI costs. These are estimated costs provided prior to carrying detailed procurement and delivery assessment processes.
3. 'Development costs (pre-funded)' is the amount of development costs which has been covered by the existing HOWSUM development funding baseline allowance of £20.6m. See Section 2.6.6.

4. 'Development costs (request)' is the amount of additional development funding required to progress the relevant island interventions, which the HOWSUM development funding baseline allowance does not cover.

5. The standard risk allowance covers foreseeable and fairly well understood types of risks. See Section 2.7.7 and our risk registers for more detail.

6. The extraordinary risk allowance covers [redacted] after addition of CAIs. See Section 2.7.7.

7. CAI costs are calculated as 10.8% of total project costs, after addition of project risk allowances. See Section 2.6.5.

8. This is the total additional cost of operating DEG to support the network during planned SSEN Transmission outages not previously identified within RIIO-ED2.

9. Total adjustment = (Total Outer Hebrides and Skye forecast – Development costs (pre-funded))

Table 56: Outer Hebrides and Skye allowance adjustment

6.2. Needs case and optioneering

We are not seeking additional funding for execution of interventions on the Outer Hebrides in this submission. However, we are seeking additional funding to cover the operational costs of DEG operation [redacted], and further development funding to ensure we are able to deliver recommended projects early in RIIO-ED3. The investment drivers for these elements are described further below along with the specific funding requests.

6.2.1. Operational costs [redacted]

[redacted]

[redacted] The RFI which we ran in summer 2024 (Section 2.3.3.1) identified there is interest in providing flexibility services from both commercial assets and community led schemes, but this is hampered by some complexities and barriers. While the RFI has not identified a single area where flexibility services can currently be used to completely remove the reliance on DEG, there is a potential stability service which may be available on Lewis, and we intend to start an associated procurement process for stability services from early 2025. We are hopeful there may be some service provision available from mid-2027 based on engagement with potential suppliers. This could offset running of Battery Point Power Station, with initial analysis suggesting the potential for a [redacted] saving on a 10-day outage (2020/21 price base). Given that procurement and delivery of the required service has not yet been undertaken we have not factored this assumption into our funding request at this stage.

We are also assessing the potential use of Hydrotreated Vegetable Oil (HVO) in the stations, with the concept of starting with a trial at one station in the near future. We are in the process of reviewing technical and supply chain considerations. The latest pricing we have for HVO from a supplier is [redacted] per litre (2020/21 price base), but this regularly fluctuates materially. [redacted] Again, while feasibility is being actively progressed, we have not included HVO pricing assumptions in our funding request.

We have discussed with SSEN Transmission whether there are options to [redacted]

Our baseline opex allowance across our island stations for RIIO-ED2 is [redacted] (CVR table C8 – Remote Generation Opex). Our RIIO-ED2 Business Plan submission was based on average utilisation during RIIO-ED1, Ofgem adjusted our allowance in Final Determinations to match our RIIO-ED1 allowance which was slightly lower. Our current forecasts show that we will exceed this allowance in RIIO-ED2 before we take account of the additional transmission outage requirements. The estimated cost of fuel and carbon only [redacted], and not accounting for wider operational costs, is [redacted].

[redacted]

6.2.1.1. Outage assumptions

Table 57 sets out key unit cost assumptions applied in the DEG funding calculation.

Assumption	Values
[redacted]	[redacted]

Table 57: Key DEG unit cost assumptions (2020/21 prices)

Table 58 sets out weekly operational and cost assumptions applied in the DEG funding calculation.

Weekly running values	[redacted]
Fuel (litres)	
CO_2 (tCO_2)	
Fuel (£)	
Duty reclaim (£)	
Carbon cost (£/tCO_2)	
Units generated based on fuel (MWh)	
Value of electricity (£)	
Other costs (staff / transport etc) (£)	

Table 58: DEG weekly running metrics in outage scenario (2020/21 prices)

Table 59 sets out the [redacted]. These are additional to what was forecast in our RIIO-ED2 Business Plan submission.

	[redacted]
2025/26	
2026/27	
2027/28	
2028/29[58]	

Table 59: [redacted]

6.2.1.2. Potential use of flexibility

In August 2024 we issued an RFI for island flexibility services. This has enabled us to understand the number or type of these services that could be provided for use in Scottish islands. It has identified the potential for a certain level of stability service in the Outer Hebrides later in RIIO-ED2 which we are now developing further. This could help reduce the volume of DEG operations during outage periods thereby reducing operational costs. We will continue to develop this proposal in RIIO-ED2 to help reduce the need for DEG operations, however our funding request does not reflect this potential opportunity given the early stage of its realisation.

6.2.1.3. Outages funding request

Our C8 – Remote Generation Opex baseline allowance request assumed outage frequency and durations in line with the average outturn in RIIO-ED1. At the time of our submission, future transmission scenarios and investment planning was uncertain. At Final Determinations stage, Ofgem reduced this request to align with our RIIO-ED1 allowance, not outturn. Our current RIIO-ED2 forecast shows that we will exceed these allowances purely based on our BAU operational assumptions [redacted]

[redacted]

For Shetland, our funding for fuel and carbon is provided as a pass-through allowance, on the basis that we have very little control over costs and quantities of fuel used and carbon emitted. [redacted]

58 The 2028/29 costs driven by [redacted] are not included in this funding request but will be included in our RIIO-ED3 Business Plan.

6.2.2. Development funding

6.2.2.1. HOWSUM development funding: Outer Hebrides and Skye projects

The analysis underpinning our January and July 2024 applications identified that additional capacity would be needed from Skye to supply Harris and Lewis from 2032/33, due to increased island demands. The optimum solution was determined to be a second 33kV cable between Ardmore GSP and Harris GSP. We have identified the need for development works to be started within RIIO-ED2, in order to deliver a solution for Harris and Lewis within RIIO-ED3.

It is anticipated that this development work will straddle the RIIO-ED2 and RIIO-ED3 price control periods and as such SHEPD are requesting a portion of development funding for those works being undertaken in RIIO-ED2. The development costs required within RIIO-ED2 are set out in Table 61.

We intend to utilise this development funding to progress the design of this option, ahead of our intended submission to Ofgem as part of our RIIO-ED3 proposals. As these costs were not anticipated in RIIO-ED2 and are additional to our baseline fundings, these form part of our request for allowance adjustment as part of this application.

Development activity	Detail	Estimated cost	Funding status
Route feasibility assessments	[redacted]	[redacted]	Funded through existing development funding allowance
		[redacted]	New development funding request

Table 61: HOWSUM development funding for Outer Hebrides and Skye projects (2020/21 prices)

6.2.3. Allowances for project risk and risk register

Our approach to quantifying risk for these projects is set out in Section 2.7.

6.2.3.1. Standard risk allowance

The associated risk register for the standard risk allowance is detailed in Appendix 2. This provides an estimated maximum cost of the risk and associated likelihood of the risk being incurred. A standard risk allowance of [redacted] for works required within RIIO-ED2 in the Outer Hebrides has been developed (Table 62) and is included within our adjustment request.

Risk allowance (£m, 2020/21 price base)	Standard risk attributed to development works in RIIO-ED2
Standard risk value	[redacted]

Table 62: Summary of standard risk allowance for Outer Hebrides and Skye

6.2.3.2. Extraordinary risk allowance

We have included requests for mechanisms or allowances to cover our extraordinary cost risk [redacted] At this stage we do not currently seek to recover any further extraordinary risk allowance relating to other interventions for this island group.

6.3. Conclusion - Outer Hebrides and Skye

Our current preferred position remains unaltered from that presented in our July 2024 submission and is summarised in both Table 63 below and pictorially in Figure 29. We seek no additional funds for this work in this submission other than increased development funding as forecast centrally for HOWSUM. We do however request additional funding associated with increased DEG running and carbon costs forecast during the RIIO-ED2 period.

We also note the ongoing works for installation of a [redacted] cable between Eriskay and Barra and installation of a [redacted] cable across the Eriskay causeway between South Uist and Eriskay which were detailed in our January 2024 submission and a determination has now been reached.

We will be publishing our SDP for this network area in early 2025[61] but do not expect a significant change to the current 2050 strategic plan.

Project element	Key outputs	Forecast delivery dates[1]
Skye – Uist – Harris	New 33kV submarine cable and 33kV overhead line Skye – Uist, and onshore substation upgrades - Dunvegan – Loch Carnan	Forecast delivery 2027/28 (submarine cable element 2026)[2]
	New 33kV submarine cable and onshore substation upgrades – Ardmore-Loch Pooltiel	Forecast delivery 2026/27
	New 33kV submarine cable Skye – Harris	*Forecast delivery 2031/32*
	New 33kV submarine cable and overhead line Harris – Uist	*Forecast delivery 2032/33*[3]

[1] Delivery dates are estimated, not wholly within our control and will be refined as projects are further developed.

[2] Delivery date subject to consenting approval of overhead route through Skye. Dunvegan – Loch Pooltiel OHL anticipated to be delivered in 2028. We are in parallel progressing the Ardmore – Loch Pooltiel optimisation that is planned to be used to accelerate the programme to delivery in 2026.

[3] Delivery brought forward from January 2024 submission to facilitate removal of reliance on DEG by the end of RIIO-ED3.

Table 63: Expected key outputs and years of delivery for Outer Hebrides and Skye interventions

Summary of funding request – Outer Hebrides and Skye

59 Whole system energy solutions for the Scottish Islands - SSEN

60 RIIO-2 Re-opener: Scottish and Southern Electricity Network's 2024 Skye-Uist Project | Ofgem

61 DSO Consultation Library - SSEN

Adjustment summary (£m, 2020/21 price base)	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Total adjustment for Outer Hebrides – Ardmore GSP	-	-	[redacted]	[redacted]	[redacted]	[redacted]

Table 64: Outer Hebrides and Skye allowance adjustment summary

7. SHETLAND

In Section 2 of this report we noted that there are a number of common drivers of future needs and challenges for Scottish islands, and that our overarching approach to strategic development also allows us to incorporate island-specific factors. We strongly believe that all Scottish islands should be treated consistently in RIIO-ED3, reflecting the critical point in time in decarbonisation for these communities. HOWSUM provides the key route for funding this work in RIIO-ED2.

We will build a 2050 strategic plan for Shetland that can be delivered from RIIO-ED3, undertaking similar analysis to that progressed for other Scottish islands. We have updated our understanding of the future needs of the Shetland islands recently through preparation of our Shetland – Gremista GSP SDP[62], which builds on the solutions being delivered through the Shetland Enduring Solution re-opener.[63] We are therefore seeking additional development funding to advance this 2050 strategic plan ahead of RIIO-ED3, at a critical time for the Shetland islands as they undergo substantial change and they become connected to the mainland for the first time.

We have engaged regularly with stakeholders on Shetland to understand their future requirements. We have done this in liaison with SSEN Transmission to ensure stakeholders get a whole system view of future electricity network proposals. Stakeholders have told us in particular that future requirements should support the delivery of new local on-island generation, particularly given the forthcoming connection to the GB mainland system. We will continue to liaise with stakeholders as the strategic development planning process progresses and incorporate our recommendations for Shetland in our RIIO-ED3 Business Plan.

62 Survey Details | Gremista GSP (Shetland) Strategic Development Plan - Draft for Consultation

63 Shetland Energy - SSEN

8. CONCLUSION

This funding application supports the development and operation of distribution networks supplying the Orkney and Hebridean island groups through the RIIO-ED2 period to March 2028. It provides strategic plans for each island group to 2050 and sets an intended direction for our work in RIIO-ED3, supported by associated development activities. To that end, it also recommends the inclusion of Shetland within this regulatory framework going forward. We summarise below the plans and requests associated with each island group. We welcome both engagement with Ofgem and stakeholders, and a swift determination process to facilitate our progression of these plans.

8.1. Proposals for Islay and Jura

8.1.1. 2050 strategic plan

The proposed 2050 network connecting the Inner Hebridean island group of Islay and Jura to mainland Scotland includes the following works:

- Within RIIO-ED2:
  - [redacted] Carradale – Port Ellen 33kV circuit
- Within RIIO-ED3:
  - [redacted] Jura – Islay 33kV circuit
  - [redacted] Port Ann – Knocklearach 33kV circuit
  - Port Ellen 33kV auto-close scheme
- By 2040:
  - Reconductoring of Lochgilphead – Knocklearach and Bowmore – Knocklearach 33kV circuits.

8.1.2. Funding request

We are seeking funding for the installation of [redacted] 33kV circuits between Carradale GSP and Port Ellen on Islay and development funding relating to the Port Ann to Knocklearach circuit.

8.2. Proposals for the Orkney Islands

8.2.1. 2050 strategic plan

Our Orkney proposals consider two 2050 pathways reflecting potential energy needs on the islands:

- Generation export pathway. A vision based on significant generation increase on the islands which triggers installation of a second transmission circuit. In this future scenario, the distribution network would remain at 33kV and below.

- Demand resilience pathway. A strategic plan based on islands needs being determined by demand requirements. This plan would see an upgrade of the island networks to 66kV starting in the 2030s.

Each of these proposals is described below. Both start with a new Thurso South – South Ronaldsay circuit in RIIO-ED2.

8.2.1.1. Demand resilience pathway

The proposed 2050 EHV and transmission network connecting the Orkney Islands to mainland Scotland consists of the planned transmission link to Finstown, which is due to be completed by 2028, as well as three distribution circuits:

- A new Thurso South – South Ronaldsay (Thurso South – John Groats, John Groats – Burwick, Burwick – South Ronaldsay) to be completed by 2028/29 initially operated at 33kV but constructed for eventual operation at 66kV, introducing 66kV assets to our asset base for the first time.
- PFW and PFE circuits upgraded to run at 66kV between within RIIO-ED3.

8.2.1.2. Generation export pathway

The proposed 2050 EHV and transmission network connecting the Orkney Islands to mainland Scotland consists of two 220kV circuits to Finstown as well as five 33kV circuits:

The existing PFE and PFW circuits

- A Thurso South – Ronaldsay circuit installed in RIIO-ED2 (66kV construction but operated at 33kV)
- A Thurso South – Scorradale circuit installed in RIIO-ED3
- A second Thurso South – Ronaldsay circuit installed in the 2040s

In addition, the DEG at Kirkwall would be removed and flexibility [redacted] ahead of the second transmission circuit commissioning.

8.2.2. Funding request

We are seeking funding for the common, first element to both these pathways. This is a new EHV circuit from Thurso South to St Margaret's Hope on South Ronaldsay via John O'Groats. We are proposing that the circuit is constructed at 66kV but initially operated at 33kV. This will allow us to keep open both 2050 strategic pathways in the medium term.

8.3. Proposals for Mull, Coll and Tiree

8.3.1. 2050 strategic plan

Works for this island group can be separated into two components:

- Works required for mainland to Mull
- Works required for Coll and Tiree only

8.3.1.1. Work required for mainland to Mull

The additional required intervention from the mainland to Mull detailed in Section 5.3.4.1 is required to meet future resilience needs. Whilst there are three circuits feeding Mull currently, the route from Fort William has not been designed to support Mull and does not have sufficient capacity to meet this need in the future. This work is not required until RIIO-ED3.

8.3.1.2. Works required for Coll and Tiree only

The current optimum 2050 network solution for the islands of Coll and Tiree would see a combination of the replacement of the Tiree DEG with an alternative solution[64] as well as a second 11kV cable from Mull. These works are not currently required until RIIO-ED3 with justification supported through use of the Strategic CBA.

8.3.2. Funding request

We are requesting development funding to support the progression of the mainland to Mull circuit in RIIO-ED3.

8.4. Proposals for the Outer Hebrides and Skye

8.4.1. 2050 strategic plan

The 2050 strategic plan for the Outer Hebrides was developed for the HOWSUM January and July 2024 applications. We have reviewed the applicability of this plan against updated demand and generation forecasts.

Our recommendations remain as set out in our previous applications, though we will keep these under review through 2025 as we develop our SDP for the Outer Hebrides and Skye.

8.4.2. Funding request

We are seeking development funding to progress the initial investigations required for the new Skye – Harris 2 cable which is required in RIIO-ED3. We have also re-assessed the costs associated with DEG operation between 2025/26 and 2027/28 as a result of a [redacted] and are seeking additional funding to cover our higher costs.

8.5. Proposals for Shetland

We are seeking additional development funding to develop a 2050 strategic plan for Shetland that can be delivered from RIIO-ED3, as we have for other Scottish islands. This work has already started through the recent publication of our Shetland – Gremista GSP Strategic Development Plan, and we are keen to cement this at a time of substantial change for Shetland.

64 This could be either repowered units or the addition of some form of energy storage on the islands of Coll and Tiree.

8.6. Total allowance adjustment request

The total allowance adjustment requested in this application is £158.59m, summarised in Table 65.

Total adjustment summary (£m, 2020/21 price base)	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**Total**
January and July 2024 applications - CAI adjustment	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Islay - Jura adjustment	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Orkney adjustment	-	-	-	[redacted]	[redacted]	[redacted]
Outer Hebrides and Skye adjustment	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Mull-Tiree adjustment	-	-	-	-	[redacted]	[redacted]
Whole system analysis adjustment	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Total adjustment:	**-**	**-**	**5.98**	**31.87**	**120.73**	**158.59**

Table 65: Total allowance adjustment summary

APPENDIX 1 – DEFINITIONS AND ABBREVIATIONS

Acronym	Definition	Acronym	Definition
AC	Alternating current	MCPD	Medium Combustion Plant Directive
ANM	Active Network Management	MVA	Mega Volt Ampere
CAI	Closely Associated Direct costs	MW	Megawatt
Capex	Capital expenditure	NEC ECC 3	NEC3 Engineering and Construction Contract
CAR	Construction All Risks (CAR) insurance	NOx	Nitrogen oxides
CBA	Cost Benefit Analysis	NPV	Net Present Value
CBRA	Cable burial risk assessment	OFTO	Offshore Transmission Owner
CEM	Common Evaluation Methodology	OHL	Overhead line
CMZ	Constraint Managed Zone	OIC	Orkney Islands Council
CNAIM	Common Network Asset Indices Methodology (CNAIM	Opex	Operating expenditure
CO2	Carbon dioxide	PFE	Pentland Firth East cable
CT	Consumer Transformation DFES	PFW	Pentland Firth West cable
DEG	Distributed Embedded Generation	P2/8	Engineering Recommendation P2/8
DFES	Distribution Future Energy Scenarios	RTS	Radio Teleswitch System (RTS)
DNO	Distribution Network Operator	RFI	Request For Information
DNOA	Distribution Network Options Assessment	RICE	Reach, Impact, Confidence, Effort
DSO	Distribution System Operator	RIIO-ED	Electricity distribution price control period, standing for "Revenue = Incentives + Innovation + Outputs". The previous price control period was RIIO-ED1, the current price control period is RIIO-ED2 (2023-2028), and the next price control period is RIIO-ED3 (2028 to 2033).
EAP	Environmental Action Plan	RIPEET	Responsible research and Innovation Policy Experimentations for Energy Transition
EMEC	European Marine Energy Centre	RTS	Radio Teleswitch System
ENA	Energy Networks Association	SBT	Science Based Target

Acronym	Definition	Acronym	Definition
EPCI	Engineering, Procurement, Construction, and Installation contract	SDP	Strategic Development Plan
FD	Ofgem Final Determinations	SDPR	Strategic Development Plan Process
GB	Great Britain	SDPM	Strategic Development Plan Methodology
GHG	Greenhouse gas	SEPD	Southern Electric Power Distribution, a DNO operating in central southern England, and part of SSEN
GSP	Grid Supply Point	SHEPD	Scottish Hydro Electric Power Distribution, a DNO operating in the north of Scotland, and part of SSEN
HDD	Horizontal Directional Drilling	SSE	Scottish and Southern Energy
HI	Health Index	SSEN	Scottish and Southern Electricity Networks (in this document normally referring to SSEN Distribution)
HIE	Highlands and Islands Enterprise	SSEN Transmission	Transmission company of Scottish and Southern Electricity Networks
HOWSUM	Hebrides and Orkney Whole System Uncertainty Mechanism	ST	System Transformation
HV	High Voltage	SWA	Scotch Whisky Association
HVAC	High Voltage Alternating Current	TIM	Totex incentive mechanism
HVDC	High Voltage Direct Current	UG	Underground
HVO	Hydrotreated Vegetable Oil	UM	Uncertainty Mechanism
ITT	Invitation To Tender		
KPS	Kirkwall Power Station		
kV	Kilovolt		
LCP	Large Capital Project		
LMA	Load Managed Area		
LRE	Load Related Expenditure		
LW	Leading the Way DFES		

EXTERNAL APPENDICES

APPENDIX 2 – RISK REGISTERS

APPENDIX 3A – INNER HEBRIDES: ISLAY-JURA EJP

APPENDIX 3B – INNER HEBRIDES: ISLAY-JURA DETERMINISTIC CBA

APPENDIX 3C – INNER HEBRIDES: ISLAY-JURA CEM CBA

APPENDIX 4A – ORKNEY EJP

APPENDIX 4B – ORKNEY DETERMINISTIC CBA

APPENDIX 4C – ORKNEY CEM CBA 1

APPENDIX 4D – ORKNEY CEM CBA 2

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