RIIO ED2 Engineering Justification Paper (EJP)

Mainland – Kerrera – Asset Replacement

Investment Reference No: 404_SHEPD_SUBSEA_MAINLAND_KERRERA

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Definitions and Abbreviations

Acronym	Definition
EJP	Engineering Justification Paper
CBA	Cost Benefit Analysis
CBRM	Condition Based Risk Management
IDP	Investment Decision Pack
ESA	Electricity Supply Area
EV	Electric Vehicle
FES	Future Energy Scenarios
GIS	Geographic Information System
GW	Gigawatt
kW(h)	kilowatt (hour)
MW	Megawatt
OHL	Overhead Line
PV	Photovoltaics
BSP	Bulk Supply Point
GSP	Grid Supply Point
LRE	Load Related Expenditure
LCT	Low Carbon Technology
SSEN	Scottish and Southern Electricity Network
UGC	Underground Cable

1 Executive Summary

This Engineering Justification Paper (EJP) for Scottish Hydro Electric Power Distribution (SHEPD) covers the investment required to manage the performance of the Mainland – Kerrera 1 subsea cable which is fed from Tullich 33 kV switching substation and provides supplies to 3,259 customers on Kerrera and beyond to Mull.

A number of subsea cable circuits have failed during RIIO-ED1, causing significant impact on customer interruptions, constrained generation, and have resulted in impact costs for temporary generation and CO2 emissions. There has been a review of the approach taken to attempt to identify and pre-empt the impact of subsea cable failure by using a 'monetised risk-based approach' alongside a traditional CBRM approach, which was not viewed as identifying the critical circuits for the strategic programme effectively on its own.

Delivering a safe, resilient and responsive network

The Mainland – Kerrera 1 subsea cable is 27 years old and has a health index rating of HI3 in the CNAIM asset model but this is anticipated to rise to HI5 by the end of RIIO ED2. SSEN has taken the view that HI5 cables present a significant risk to customer supplies. Furthermore, the second feeder supplying Kerrera and on to Mull also has a health index of HI3 predicted to increase to HI5 by the end of RIIO ED2. This represents a significant risk to the supplies of the 3,259 customers on Kerrera and Mull.

Following optioneering and detailed analysis, as set out in this paper, the proposed scope of works for the existing Mainland to Kerrera 1 circuit are as follows:

- Installation of new 33 kV submarine cable between Mainland and Kerrera following a similar route to the existing subsea cable.
- Tie new cable in to existing 33kV network.
- Decommission existing cable.

The estimated cost to deliver the preferred solution is £[redacted] m. The delivery programme for all subsea cables in ED2 will be determined through detailed planning and engagement with marine installation contractors and cable procurement opportunities. For simplicity, where required, the delivery year is assumed as 2026/27 in this EJP and this will be refined as our programme develops.

This scheme delivers the following outputs and benefits:

- Improves reliability and reduces the potential for customer interruptions due to a subsea cable fault.
- Reduces the risk of incurring CI/CML costs and constrained generation.

Option 2, replacement with a similar sized cable was selected as the preferred option providing the least cost, best NPV option. However, further investigation into future forecast demand growth for this circuit and the Mainland - Kerrera 2 circuit will be required at the time of detailed design, to confirm the existing cable size will be suitable to provide capacity over the lifetime of the new asset.

All subsea cable EJPs should be read in conjunction with the ***Scottish Islands (Annex 8.1)*** of our RIIO-ED2 Business Plan.

2 Investment Summary Table

Table 1 below provides a high-level summary of the key information relevant to this Engineering Justification Paper (EJP).

Table 1: Investment Summary

<table>
<tr><td>Name of Programme</td><td colspan="3">Mainland – Kerrera 1 Asset Replacement</td></tr>
<tr><td>Primary Investment Driver</td><td colspan="3">The Primary Investment Driver described within this EJP is the requirement to reduce the overall monetised risk associated with the loss of the existing subsea cable.</td></tr>
<tr><td>Investment reference/mechanism or category</td><td colspan="3">Cost Benefit Analysis reference:
404_SHEPD_SUBSEA_MAINLAND_KERRERA</td></tr>
<tr><td>Output reference/type</td><td colspan="3">As above</td></tr>
<tr><td>Cost (£m)</td><td colspan="3">£[redacted]</td></tr>
<tr><td>Delivery year</td><td colspan="3">ED2 (2026/27)</td></tr>
<tr><td>Reporting Table</td><td colspan="3">CV7: Asset Replacement</td></tr>
<tr><td>Outputs included in RIIO ED1 Business Plan</td><td colspan="3">No</td></tr>
<tr><td rowspan="2">CV7 - Asset Replacement
RIIO ED2 Spend (£m)</td><td>Asset Category</td><td>ED2 (£m)</td><td>Total (£m)</td></tr>
<tr><td>EHV Subsea Cable</td><td>[redacted]</td><td>[redacted]</td></tr>
</table>

3 Introduction

This Engineering Justification Paper (EJP) for Scottish Hydro Electric Power Distribution (SHEPD) covers the strategic investment required to manage the performance of the Mainland – Kerrera 1 subsea cable which is fed from Tullich 33 kV switching substation and provides supplies to Kerrera and onward to Mull. The 70 mm^2 EPR SWA 33 kV cable is 0.866 km long and provides a connection from the Mainland to Kerrera.

The Primary Investment Driver described within this EJP is based on reducing the overall monetised risk associated with this circuit which has been determined from the "Strategic Subsea Cable CBA Model" developed to determine the overall replacement / augmentaiton strategy for all subsea cables by mitigating the monetised risk associated with the subsea cable assets. The model evaluates the probabilty of failure, the cost of intervention and the impact cost and used this assesment across the asset population to determine the initial investment method to be considered. Further detail on the Strategic Subsea Cable CBA Model is provided in the ***Scottish Islands (Annex 8.1).***

Section 4 provides high-level background information for this subsea asset category and explains the importance of this asset for our electricity distribution network and our network customers, and the motivation for ensuring our subsea cables are in good health over the course of RIIO-ED2 and beyond.

Sections 5 and 6 provide a summary of the corresponding intervention options which can be deployed as a solution to these condition related investment drivers.

Section 7 provides a detailed analysis then describes the cost and volumes arising from the preferred intervention options as supported by the Cost Benefit Analysis (CBA) results which complements this EJP.

Section 8 provides an overview of the deliverability and risk management considerations being adopted for the transition from RIIO-ED1 in to RIIO-ED2, and the delivery of subsea cable asset replacement projects.

Section 9 provides an overview of the information presented throughout the EJP and concludes a proposed solution recommended to manage the business case presented.

4 Background Information and Analysis

4.1 How Do We Determine Our Intervention Priorities

introduced our Condition Based Risk Management (CBRM) system in 2014 following the RIIO-ED1 Business Plan submission. However, since August 2017, we switched over fully to maximise utilisation of the Common Network Assets Indices Methodology (CNAIM) modelling for all asset classifications applicable for the RIIO-ED1 requirements with the data inputs outlined in the Information Gathering Plan (IGP).

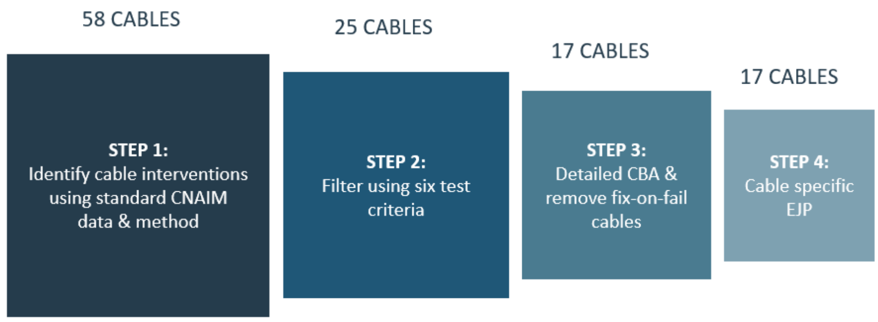
The RIIO-ED2 Business Plan submission has been based on the latest version of the industry standard CNAIM v2.1 which was approved for use in RIIO-ED2 by Ofgem in April 2021. The supporting data used in the modelling of this submission is based on the reported position of our asset condition for RIIO-ED1 Year 6 at the end of August 2021.

The full details of the Energy Network Association's NARMs Electricity Distribution Working Group (NEDWG) publication on CNAIM v2.1 is available on Ofgem's website. For further detail on our RIIO-ED2 NARMS strategy please see ***Safe and Resilient (Annex 7.1).***

Our proposed investment programme in ED2 is asset data led; refined and iterated by overlaying the industry standard risk management methodology with enhanced risk modelling and cable specific cost benefit analysis. We are proposing planned replacement of cables where the certainty of need is highest driven by high probability and impact of failure in ED2.

We have adopted a four-step funnel approach, as shown below, to determine the interventions required on the network. This approach allows us to filter from an initial examination of the complete list of subsea cables we operate to a credible and deliverable list of interventions which are supported by robust analysis. Steps 1 to 3 are set out in detail within our ***Scottish Islands (Annex 8.1).***

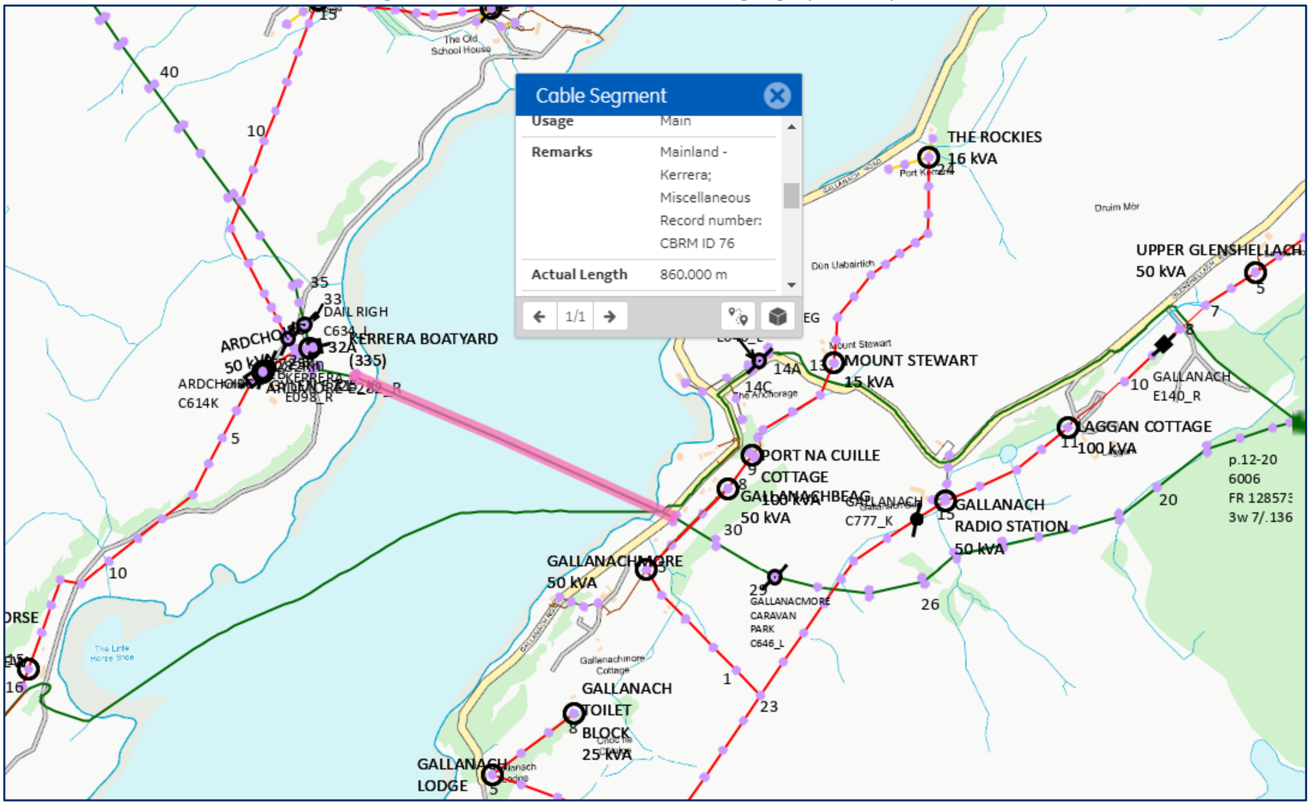
This EJP covers Step 4 for the Mainland – Kerrera cable which has qualified as requiring intervention. We set out here our approach to clearly justify why the circuit design approach is being proposed and associated costs are the most economic and efficient and what work would be required to deliver on these investments.



4.2 Demand and Generation Forecast

There are two cables from the Mainland to Kerrera, and both cables are programmed for replacement. This EJP focusses on the replacement of Mainland – Kerrera 1 cable. The 70 mm² EPR SWA 33 kV cable is 0.866 km long, has been in service for 27 years and provides a connection from the Mainland to Kerrera as shown in figure 1 below.

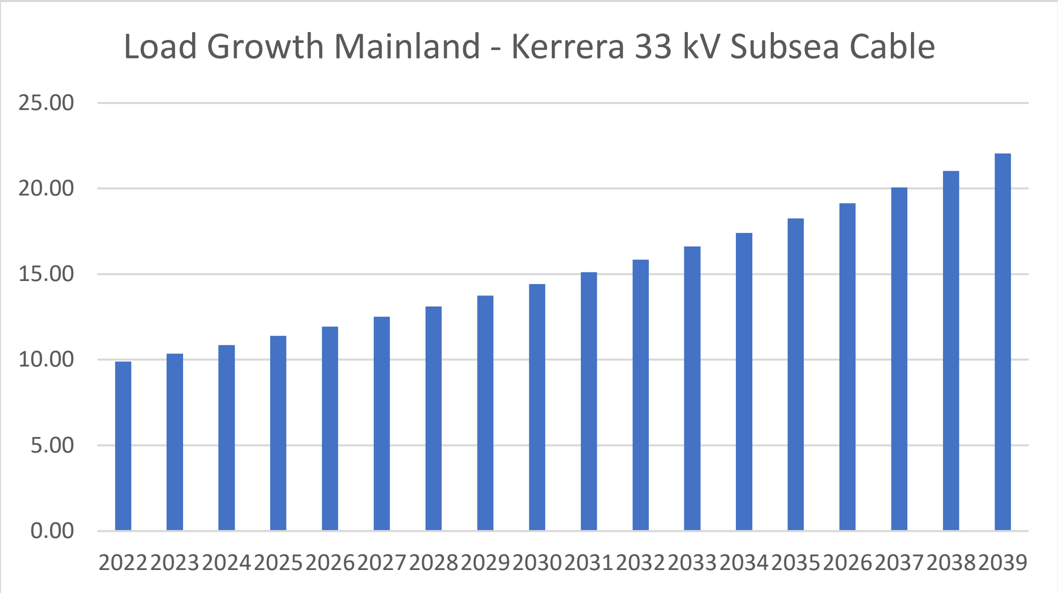
Figure 1: Mainland – Kerrera Network geographical layout.



The Mainland – Kerrera 33 kV subsea cable is one of two cables that run from the mainland to the Island of Kerrera. These two cables not only feed Kerrera but feed onward to the Island of Mull, Iona, Coll and Tiree.

The 70 mm² EPR SWA 33 kV cable is rated at 14.3 MVA with a current maximum demand of 9.7 MVA (67.6% of the cable rating). The average annual DFES growth for the area is 2.235% and forecast demand at the end of ED2 is expected to be 11.5 MVA (80.7% of the cable rating). The demand projection is shown in Figure 2 below.

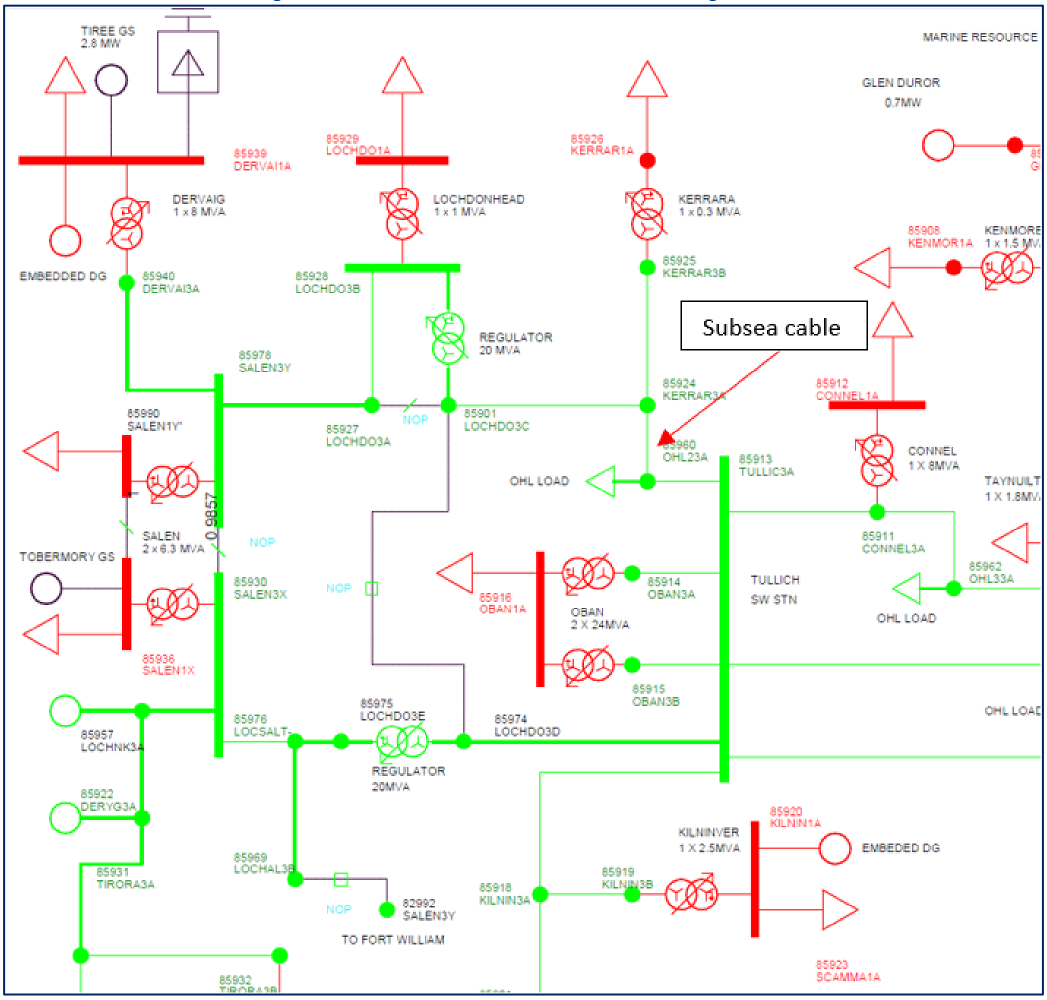
Figure 2- Load Forecast Mainland – Kerrera 1 33 kV Feeder



4.3 Existing Network Arrangement

The existing 33 kV network configuration is shown figure 3 below.

Figure 3 - Mainland – Kerrera 1 Network Arrangement



4.4 Existing Asset Condition

The Mainland – Kerrera 1 33kV cable is 27 years old and has a health index rating of HI3 in the CNAIM asset model, rising to HI5 by the end of RIIO ED2. The cable has a Probability of Failure of 0.0106 at the start of ED2 rising to 0.0294 at the end of ED2. SSE has taken the view that HI5 cables present a significant risk to customer supplies, and as such intends to replace HI5 cables on the network.

5 Options Considered

This section of the report sets out the investment options that have been considered for intervention on the existing cable. The approach taken has been to ensure investment options demonstrate best value for money for network customers.

5.1 Summary of Options

Table 2 below provides a summary of the six (6) investment options under consideration along with the advantages and disadvantages associated with each. A more detailed description of each option is then provided within the following sub-sections.

Table 2 - Summary of Investment Options

Option	Description	Advantages	Disadvantages	Results
1. Do Minimum	Replace on failure	Low initial cost	Availability of material and resource when required. High cost of repair where practical with unknown resolution of the fault	Rejected
2. Replace	Replace the cable with the same size cable on the same route	Improves HI. Provides new life cycle and allows reduced probability of failure	Remains single circuit security retaining a risk of incurring high costs due to outages.	Recommended option
3. Replace with larger cable	Replace the cable with a larger cable on the same route	Improves HI. Provides new life cycle and allows greater protection of cable. Provides for future load and generation growth	Remains single circuit security retaining a risk of incurring high costs due to outages.	Rejected
4. Augmentation	Lay a new cable and retain the old cable connecting new cable into the 11 kV network in parallel	Similar cost to replacement. Provides N-2 for the remainder of the existing cable life.	Improves the reliability with three cables in commission, however, would fall back to N-1 following the failure of the existing circuit.	Rejected
5. Augmentation larger cable	Lay a new cable and retain the old cable will provide greater capacity for future growth	Similar cost to replacement. Provides N-2 for the remainder of the existing cable life.	Improves the reliability with three cables in commission, however, would fall back to N-1 following the failure of the existing circuit.	Rejected

Option	Description	Advantages	Disadvantages	Results
	in generation and load.	Provides for future load and generation growth.		
6. Two new cables existing route	Lay two new cables along the known route of the existing cable and provide a firm connection.	Provides full N-2 security	Highest cost	Rejected

6 Analysis and Cost

The details of each option are described below:

6.1 Option 1: Do-Minimum

The "Do Minimum" Option is for the repair or replacement of the cable on failure. Based on the age, health index and length of the cable, repair would be by replacement of the entire subsea section of the cable following a similar route to that of the existing cable shown previously.

In the event of a cable failure supplies to 3,259 customers would be interrupted and 0.4 MW of generation constrained off. All customers can be supplied from an alternative supply; however, the generation will be constrained until the cable fault is repaired. The generic model has assumed this will be for a period of six months to allow the mobilisation resources to replace the cable.

The CI/CML, and constrained generation costs during the outage are estimated at £143 k.

The emergency replacement [redacted] km of subsea cable following a similar route to the existing cable as shown in figure 1 above has been estimated based on a planned replacement cost uplifted by [redacted] % to reflect the premium paid during an emergency situation. This gives a total anticipated expenditure of £[redacted] k. This provides for an equivalent size cable (95 mm²) with a capacity of 16 MVA.

This gives an estimated total cost of failure of £[redacted] k

This option avoids any initial cost and, depending on how long the cable lasts, may defer expenditure beyond ED2. However, the cost of an emergency replacement would be higher than a planned replacement if the cable fails and it incurs the impact and environmental cost. The NPV over 45 years for this option is -£2,090 k

This option was rejected, as the replacement in an emergency would increase planned replacement costs by [redacted] % and put a significant number of customers at risk, should the alternative cable fail.

6.2 Option 2: Replace with same size cable

Replacing the cable with a new 95 mm², subsea cable with a capacity of 16 MVA will impact the HI and Probability of Failure resulting in a change to the characteristics set by the age and condition. The new cable will be connected to the existing network points and the old cable disconnected. This option is the proposed replacement solution of the cable during ED2 with a new 95 mm^2 cable. This will avoid the costs incurred in the event of a failure.

The replacement 0.866 km of subsea cable, following a similar route to the existing cable, as shown in figure 1 above has been estimated at a cost of £[redacted] k.

The Probability of Failure is anticipated to increase from 0.0106 to 0.0294 by the end of ED2, without intervention. The PoF will reduce to 0.010 following replacement. This drives the NPV calculation which in this case is -£1,860 k.

This is the preferred option; however, the demand growth needs further investigation to confirm the growth forecast figures on this circuit and the Kerrera 2 circuit. This will be done in the detail engineering phase and ensure the replacement cable is suitably rated to provide for anticipated requirements over the lifetime of the asset.

6.3 Option 3: Replace with a larger 185 mm² cable

This option is similar to option 2, laying a new 185 mm² subsea cable with a capacity of 24 MVA rather than the like for like replacement in option 2. This cable has a higher initial cost, however, has the advantage over option 2 that it would cater for greater future load growth.

The cost of this option is estimated at £[redacted] k.

As in Option 2, the reduction in the Probability of Failure and availability of the original circuit drives the NPV calculation which in this case is -£1,930 k.

While Option 2 is the preferred option, subject to further investigation of demand growth for this circuit and the Mainland - Kerrera 2 circuit, a larger cable may be required.

6.4 Option 4: Augmentation with same sized cable

This option is similar to option 2, laying 95 mm², but retaining the existing cable until it becomes faulty. This would incur additional costs for connection of the new cable into the 33 kV network on Mainland and Kerrera.

This would provide enhanced security with three circuits until the existing cable became faulty at which time the supply would revert to a single circuit as in option 2.

The cost of this option is estimated at £[redacted] k.

As in Option 2, the reduction in the Probability of Failure and availability of the original circuit drives the NPV benefits calculation which in the case is -£1,910 k.

This option was rejected as it does not provide any additional benefits to Option 2 to justify the additional cost of investment.

6.5 Option 5: Augmentation with larger cable

This option is similar to option 4 but utilising a 185 mm² cable instead of the 95 mm² and would cater for any potential growth.

This like option 4 provides three cable connections to Kerrera until the failure of the existing cable.

The cost of this option is estimated at £[redacted] k.

As in Option 4, the reduction in the Probability of Failure and availability of the original circuit drives the NPV benefits calculation which in this case is -£1,980 k.

This option was rejected as it does not provide any additional benefits to Option 2 to justify the additional cost of investment.

6.6 Option 6: Installation of two new cables on the existing route

This was considered due to the improvement in reliability and security provided by two new cables which would ensure that in the event of a subsea cable fault supplies would be maintained and avoid impact costs and constraint costs. The laying of the two cables together under the same contract is expected to allow cost saving of 10% on the second cable compared to the first. This has been costed on 95 mm² cables and would provide firm N-2 capacity until loading exceeds the capacity of a single cable.

The cost of this option is estimated at £[redacted] k.

As with other options the reduction in probability of failure by replacing the existing subsea cable drives the NPV calculation, which in this case is -£3,200 k.

This option was rejected as the higher cost does not provide any additional benefits to justify the investment.

7 Summary of Cost Benefit Analysis (CBA)

This section of the report provides an overview for each option from the Cost Benefit Analysis (CBA). A detailed exercise has been undertaken to support the investment strategy that is described within this EJP for the 6 options, as described below:

7.1 Summary of Costs

Our RIIO-ED2 Business Plan costs are derived from our outturn RIIO-ED1 expenditure. For our Subsea cable projects, our Unit Costs have been derived from analysing costs pertaining to delivered projects completed during RIIO-ED1 and are therefore based on actual costs. For cable installation activities the delivered projects were competitively tendered utilising our Subsea Cable Installation Framework and cable costs have been benchmarked against recently completed tender events. By tying our costs back to reported, outturn, real life data this approach provides multiple data points and provides a high level of cost confidence in our Business Plan cost forecast for RIIO-ED2.

As our Business Plan has developed, project scopes and costs have been refined, especially with the input of valuable stakeholder feedback on our draft proposals. This final Business Plan submission cost forecast contains that refinement, and the changes are captured within our supporting plan documentation. The generic Unit Cost rates used in the draft Business Plan have now been revised following extensive analysis. This is further defined within ***Scottish Islands (Annex 8.1).***

A summary of the costs for each option is given in Table 3 below.

Table 3 - Summary of Costs

Options	Unit	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Option 1 – Do Minimum	£m	-	-	-	-	[redacted]	[redacted]
Option 2 – Replace same size	£m	-	-	-	[redacted]	-	[redacted]
Option 3 – Replace larger cable	£m	-	-	-	[redacted]	-	[redacted]
Option 4 – Augment same size	£m	-	-	-	[redacted]	-	[redacted]
Option 5 – Augment larger cable	£m	-	-	-	[redacted]	-	[redacted]
Option 6 – two cables	£m	-	-	-	[redacted]	-	[redacted]

7.2 Cost Benefit Analysis Comparisons

For comparison purposes, it has been assumed in the CBA that the existing cable fails in 2028. Therefore, the augmentation options will have the benefits of N-1 operation until this time. However, the benefits of N-1 operation will increase if the existing circuit remains in service beyond this time.

Although there is little difference between options 1 to 5 on NPV over 45 years, of the options considered in the CBA, Option 2 has been selected as it provides the least cost and best NPV. In addition, SHEPD will be operating in close proximity replacing the other Mainland – Kerrera 2 cable which is in similar condition to this cable. Efficiencies will be gained and projects de-risked by replacing both at the same time. This will maximise customer value and also ensure the best security of supply is maintained to this customer group.

Table 4 - Summary of NPV

Options	NPV After 45 Years (£m)
Option 1 – Do Minimum	-2.09

Options	NPV After 45 Years (£m)
Option 2 – Replace same size	-1.86
Option 3 – Replace larger cable	-1.93
Option 4 – Augment same size	-1.91
Option 5 – Augment larger cable	-1.98
Option 6 – Reinforcement with two cables	-3.20

7.3 Volume on Preferred Option

The option selected requires a new cable to be laid along the existing cable route and connected into the current 33 kV network, with the existing cable disconnected.

Table 5 – Volume for Preferred Option

Asset Category	Unit	2023/24	2024/25	2025/26	2026/27	2027/28	Total
33 kV subsea	km	-	-	-	[redacted]	-	[redacted]

8 Deliverability & Risk

Our ***Deliverability Strategy (Annex 16.1)*** describes our approach to evidencing the deliverability of our overall plan as a package, and its individual components. Testing of our EJPs has prioritised assessment of efficiency and capacity, and this has ensured that we can demonstrate a credible plan to move from SSEN's RIIO-ED1 performance to our target RIIO-ED2 efficiency.

We have also demonstrated that SSEN's in house and contractor options can, or will through investment or managed change, provide the capacity and skills at the right time, in the right locations. This assessment has been part of the regular assessment of our EJPs, IDPs and BPDTs. For the investment proposed under our subsea cable related EJPs, we have been developing our RIIO-ED2 Commercial & Deliverability Strategy and engaging with our supply chain to ensure we can deliver the solutions proposed, while identifying and managing the risks presented by the complex and challenging nature of the projects.

Our deliverability testing has identified major strategic opportunities which is relevant to all subsea EJPs.

- In RIIO-ED2, SSEN will change the way Capital Expenditure is delivered, maximising synergies within the network to minimise disruptions for our customers. This is particularly relevant for a Price Control period where volumes of work are increasing across all work types.
- The principle is to develop and deliver programmes of work, manage risk and complexity at programme level and to develop strategic relationships with our suppliers and partners to enable efficiency realisation. This potentially includes refining our contracting strategies to improve our risk profiles.
- Transparency with the supplier in terms of constraints, challenges, outage planning and engineering standards will capitalise on efficiencies, supported by a robust contracting strategy.

The delivery programme for all subsea cables in RIIO-ED2 will be determined through detailed planning and engagement with marine installation contractors and cable procurement opportunities. In addition, early stakeholder engagement will significantly de-risk project schedules and deliver value.

We are already identifying opportunities for improved efficiency and improved risk management of our projects and associated programmes. As part of the planning for our final Business Plan submission, we have explored subsea cable project 'bundling' by cable type and geographic location. Our delivery year for each EJP is based on this initial assessment, which will be further explored and then refined with our supply chain in early 2022 to identify the optimal equilibrium of project deliverability and risk management.

9 Conclusion

The purpose of this Engineering Justification Paper (EJP) has been to provide the investment justification and option selection for the 33 kV subsea cable between Mainland and Kerrera.

Due to the number of subsea cable faults in RIIO-ED1, including the Pentland Firth East Cable, the approach taken for EIIO-ED2 has been to pre-empt failures where possible. The creation of the monetised risk CBA model allows for the circuits which are likely to have the biggest impact, should a failure occur, to be addressed. This approach considers the subsea population within the generic CBA model to help identify the appropriate circuits to be replaced.

The Mainland – Kerrera 1 subsea cable is 27 years old and has a health index rating of HI3 in the CNAIM asset model raising to HI5 by the end of RIIO ED2. SSE has taken the view that HI5 cables present a significant risk to customer supplies, and as such intends to replace HI5 cables on the network. As previously discussed there are two feeders supplying Kerrera, it should be noted that the Mainland - Kerrera 2 subsea cable also has a health index of HI3 raising to HI5 by the end of RIIO ED2 and represent a significant risk to the supplies of the 3,259 customers on Kerrera and Mull.

Option 2, replacement with a similar sized cable has been selected as the preferred solution, as this is the least cost option and provides the best NPV. However, further investigation into the forecast demand growth for this circuit and Kerrera 2 circuit will be required to confirm if larger cables are required for both circuits over the cable life.

Planning the replacement of both Kerrera 1 and Kerrera 2 subsea cables at the same time offers potential savings on engineering, surveys, procurement and mobilisation costs, whilst also significantly de-risking project delivery. A separate EJP has been produced for the Mainland – Kerrera 2 cable.

CV7 Asset Replacement	Asset Category	ED2 (£m)
CV7 RIIO ED2 Spend (£m)	EHV Subsea Cable	[redacted]