RIIO ED2 Engineering Justification Paper (EJP)

Kintyre – Gigha – Asset Replacement

Investment Reference No: 414_SHEPD_SUBSEA_KINTYRE_GIGHA

Contents

Definitions and Abbreviations

Acronym	Definition
EJP	Engineering Justification Paper
CBA	Cost Benefit Analysis
CBRM	Condition Based Risk Management
CNAIM	Common Network Asset Indices Methodology
IDP	Investment Decision Pack
ESA	Electricity Supply Area
EV	Electric Vehicle
FES	Future Energy Scenarios
GIS	Geographic Information System
GW	Gigawatt
HDD	Horizontal Directional Drilling
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 risk and performance of the Kintyre - Gigha subsea cable which is fed from Ballure 33/11 kV Primary substation and provides supplies to 125 customers on Gigha.

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 Kintyre - Gigha subsea cable is 3.65km long and has been in service for 34 years. It currently has a health index of HI3 and criticality index of CI1. It is anticipated to become an HI4 C1 by the end of ED2 with no intervention. The cable had previously been identified for proactive replacement back in 2016 and progressed through to Marine Licence Pre-application Consultation (PAC) with the relevant stakeholders and statutory consultees. The replacement was put on hold following the PAC event due to other fault / replacement projects. However, recent stakeholder engagement has re-emphasised the requirement for the cable to be replaced from a capacity and reliability perspective.

Following optioneering and detailed analysis, as set out in this paper, the proposed scope of works are:

- Replace the exisiting Kintyre – Gigha 11 kV subsea cable by laying a new 11 kV submarine cable between Kintyre and Gigha.
- Decommission the existing cable.
- Tie in new cable to existing 11kV network

The estimated cost to deliver the preferred solution is £[redacted]. 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 2023/24 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 impact costs, constrained generation, temporary generation and CO_2 impacts, particularly relevant if larger wind turbines are installed by the local community.
- Reduces the monetised risk on the Kintyre - Gigha cable, forecast to be £57,865 by the end of ED2 with no intervention, down to £13,913.

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

Name of Programme	Kintyre – Gigha Asset Replacement		
Primary Investment Driver	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.		
Investment reference/mechanism or category	Cost Benefit Analysis: 414_SHEPD_SUBSEA_KINTYRE_GIGHA		
Output reference/type	As above		
Cost (£m)	£[redacted]		
Delivery year	ED2 (2023/24)		
Reporting Table	CV7: Asset Replacement		
Outputs included in RIIO ED1 Business Plan	No		
CV7: Asset Replacement RIIO ED2 Spend (£m)	Asset Category	ED2 (£m)	Total (£m)
	HV Subsea Cable	[redacted]	[redacted]

3 Introduction

This Engineering Justification Paper (EJP) for Scottish Hydro Electric Power Distribution (SHEPD) covers the investment required to manage the performance of the Kintyre - Gigha subsea cable which is fed from Ballure 33/11 kV Primary Substation and provides supplies to Gigha. The 35 mm² PILC 'H' DWA 11 kV cable is 3.65 km long and provides a connection from Tower House on Kintyre to Gigha Air Terminal on Gigha.

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

We 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).

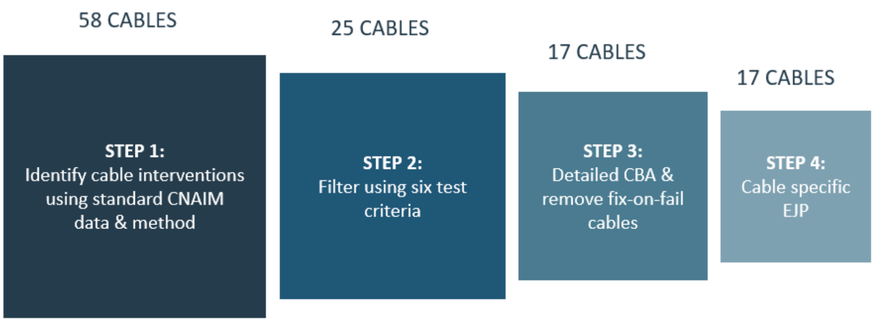
The RIIO-ED2 Business Plan submission has been based on the latest version of the industry standard CNAIM v2.1 which was approved for use in RIIO-ED2 by Ofgem in April 2021. The supporting data used in the modelling of this submission is based on the reported position of our asset condition for RIIO-ED1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

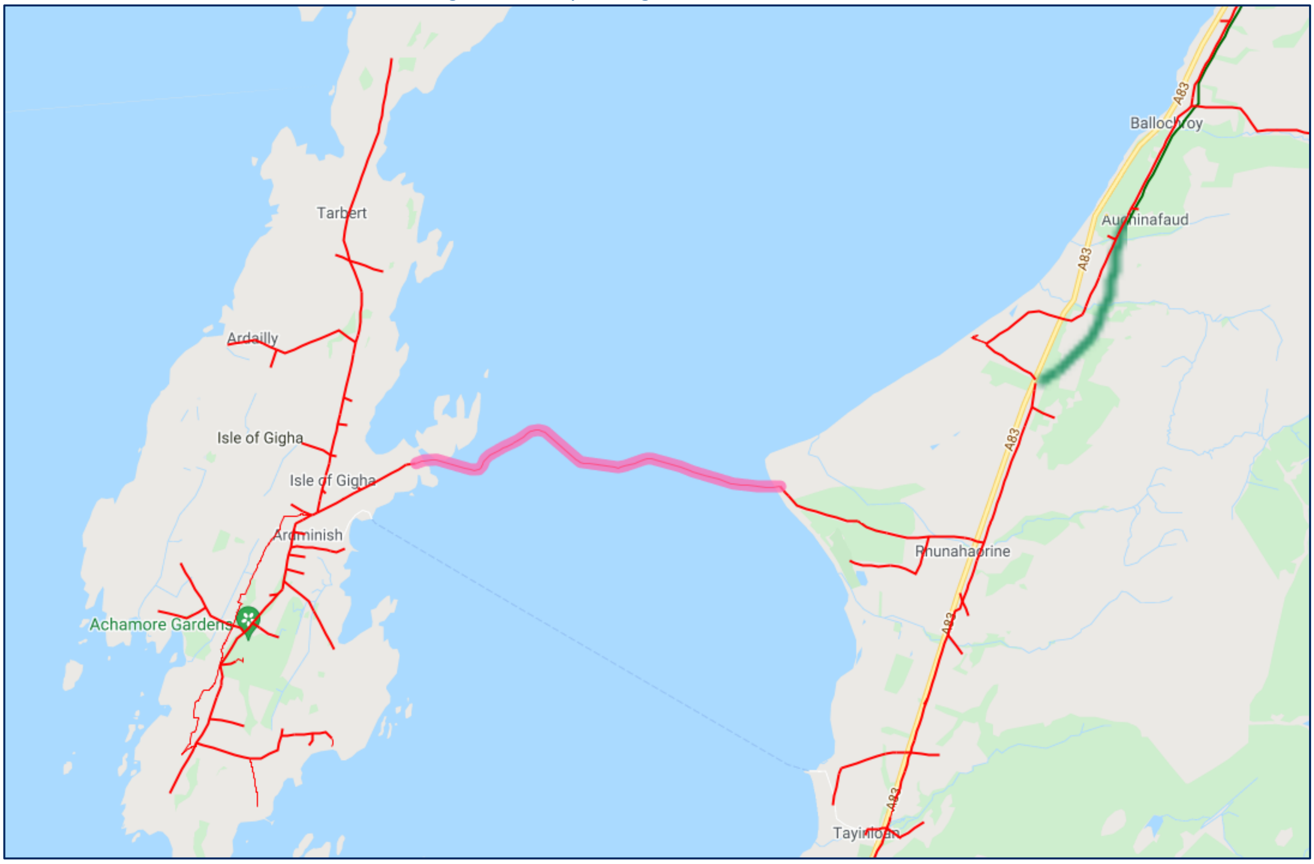
This EJP covers Step 4 for the Kintyre - Gigha cable which has qualified as requiring intervention. We set out here our approach to clearly justify why the circuit design approach is being proposed and associated costs are the most economic and efficient and what work would be required to deliver on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



4.2 Demand Forecast

The Kintyre - Gigha subsea cable currently provides supplies to 125 customers on Gigha. The existing cable is an 11kV 35 mm^2 PILC 'H' DWA cable, been in service for 34 years and is 3.65 km long. The existing cable installation route is indicated below in Figure 1.

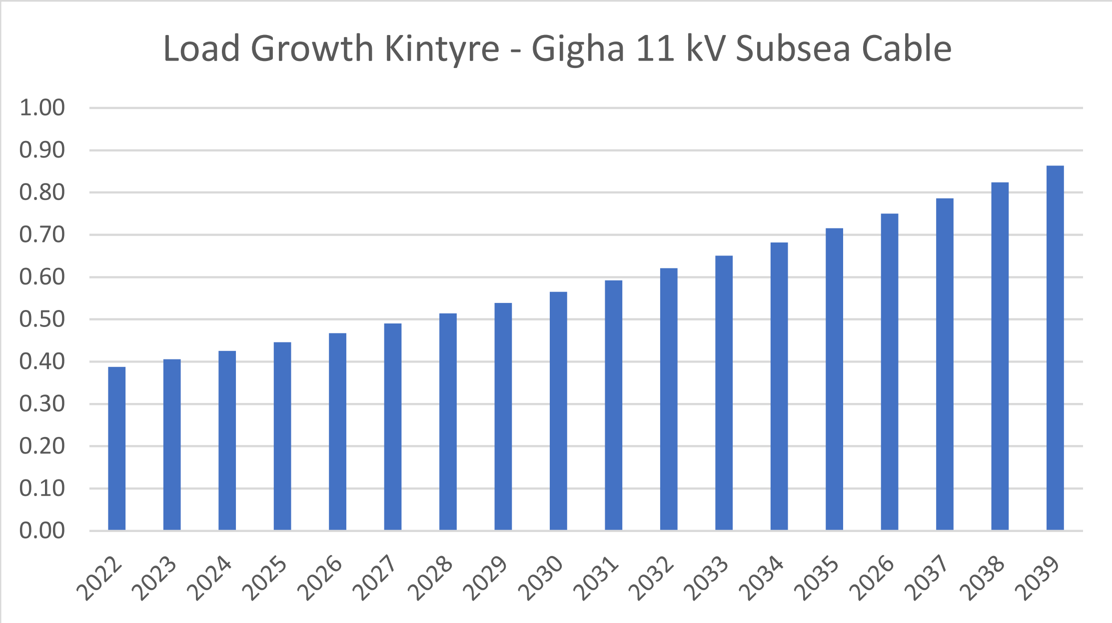
Figure 1 – Kintyre - Gigha Subsea Cable Route



The cable is an 11 kV 35 mm^2 PILC 'H' DWA rated at 2.9 MVA. The current maximum demand on the Kintyre - Gigha cable is 0.38 MVA (12.9% of the cable rating). The average annual DFES growth for the area is 1.948%, and forecast demand at the end of ED2 is expected to be 0.44 MVA (15.4% of the cable rating). The demand projection is shown in Figure 2 below.

The island currently has three wind turbines generating up to 1MW that is constrained by the capacity of the current cable. The age and general health of the current cable also presents a significant risk to the local community and their desire to progress towards Net Zero.

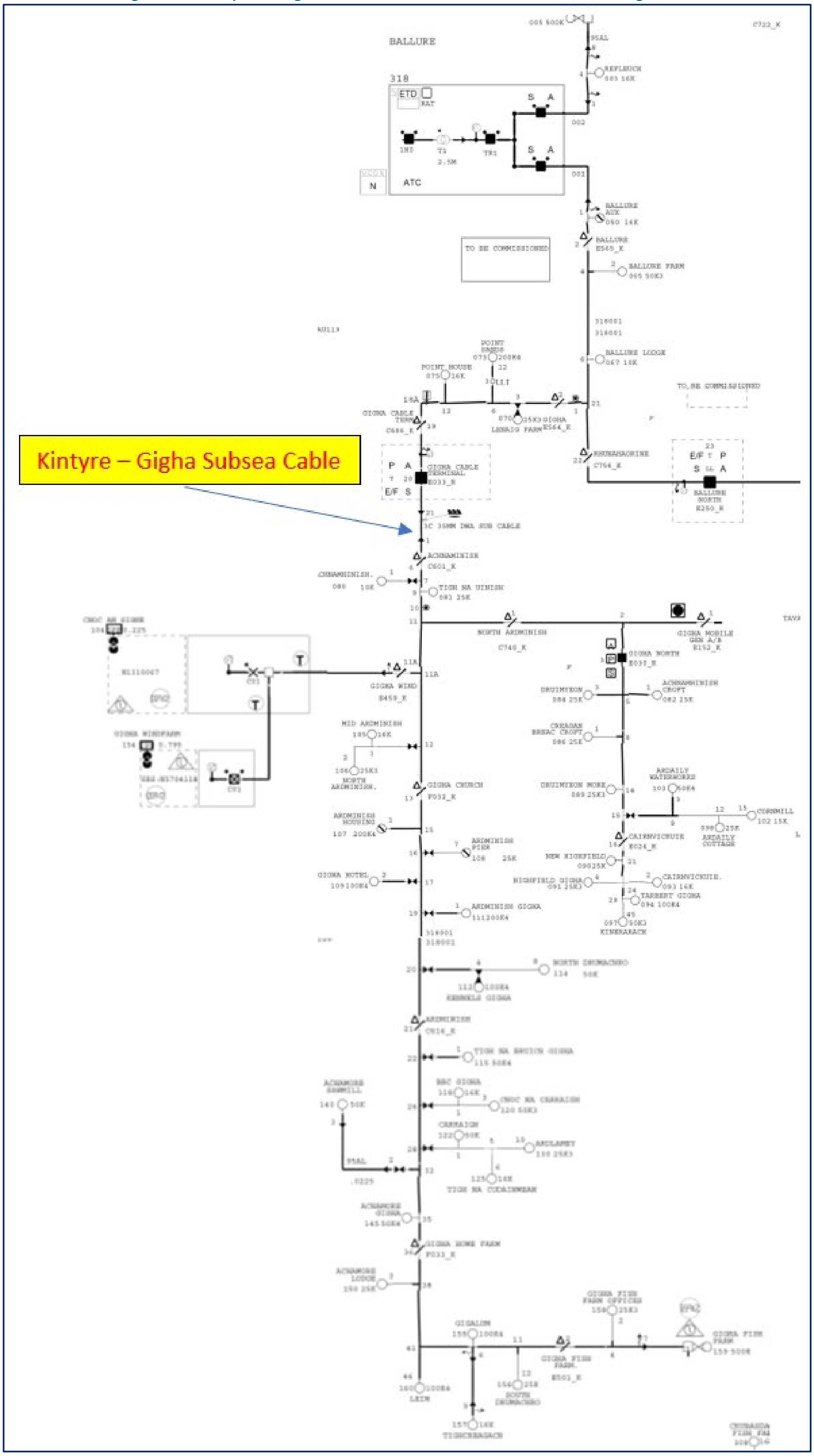
Figure 2- Load Forecast Kintyre - Gigha - 11 kV Feeder



4.3 Existing Network Arrangement

The subsea cable from Rhunahaorine Point on Kintyre to the 11kV network near Achnamhinish on Gigha forms part of the 11 kV network fed from Ballure 33/11 kV Primary substation, Figure 3 below shows the existing network arrangement.

Figure 3 – Kintyre – Gigha 11 kV subsea cable and network arrangement



4.4 Existing Asset Condition

The Common Network Asset Indices Methodology (CNAIM) models maintained by SSEN provide a Health and Criticality Index for each individual asset. This is calculated using a variety of asset-specific data which includes basic parameters in addition to the observed and measured condition (where available) of each asset.

The Kintyre - Gigha subsea cable was installed in 1987 and has been in service for 34 years it currently has a heath index HI3 and criticality index of CI1 and is anticipated to become an HI4 C1 by the end of ED2 with no intervention.

5 Options Considered

This section of the report sets out the investment options that have been considered to resolve the risk and impact issues associated with this cable. A holistic approach has been taken to ensure that the investment options identified represents best value for money for network customers.

5.1 Summary of Options

Table 2 below a 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 of supply, retaining a risk of incurring high costs due to outages. Improves the reliability with the new circuit	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 in short to medium term.	Remains single circuit security of supply, 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-1 for the remainder of the existing cable life with marginal increased cost over option 2.	Improves the reliability with two cables in commission, however, would fall back to single circuit following the failure of the existing circuit. This would then revert to the equivalent of Option 2.	Rejected

Option	Description	Advantages	Disadvantages	Results
5. Augmentation larger cable	Lay a new cable and retain the old cable will provide greater capacity for future growth in generation and load.	Similar cost to replacement. Provides N-1 for the remainder of the existing cable life with marginal increased cost over option 2. Provides for future load and generation growth in short to medium term	Improves the reliability with two cables in commission, however, would fall back to single circuit following the failure of the existing circuit. This would then revert to Option 3.	Rejected
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-1 security of supply and removes the impact of a failure for a single circuit increasing reliability.	Highest cost	Rejected

6 Analysis and Cost

The details of each option are described below:

6.1 Option 1: Do-Minimum – Replace on failure

The “Do Minimum” Option has been considered as a repair or replacement of the cable on failure. Based on the age, health index and length of this cable, it is anticipated following a fault a replacement of the entire subsea section of the cable following a similar route to that of the existing cable.

In the event of a cable failure supplies to 125 customers would be interrupted and 1 MW of generation constrained off. To supply the demand, customers would require the deployment of mobile generation for the duration of the outage. The generic model has assumed this will be for a period of six months to allow the mobilisation of resources to replace the cable.

The CI/CML, temporary generation costs, CO_2 costs and constrained generation costs during the outage are estimated at £577k.

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 in an emergency situation. This gives a total anticipated cost for a replacement of £[redacted]k. This provides for an equivalent size cable (95 mm²) to provide capacity of 4.9 MVA which would satisfy the demand forecast until 2039, based on CT DFES forecasts.

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

This option avoids any initial cost and depending on how long the existing 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 -£3,010 k

This option was rejected, as it would incur impact cost, constrained generation cost and reputational damage. In addition, the replacement in an emergency would increase planned replacement costs by [redacted]%.

6.2 Option 2: Planned replacement during ED2

This option is to replace the current 35 mm² cable with a new 95 mm² subsea cable and will reduce the HI and Probability of Failure. The new cable will be connected to the existing network points and the old cable disconnected. Due to SHEPD now procuring 95mm² subsea cable as a minimum standard this inherently will also increase the potential capacity of the circuit, therefore reducing the current constraints on island distributed generation. This will avoid the costs incurred in the event of a failure.

The replacement [redacted] 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 would increase from 0.0446 to 0.1003 by the end of ED2 should no intervention take place. The PoF will reduce to 0.017 following intervention and delivery of this option. This drives the NPV calculation which in this case, over 45 years is -£2,430 k.

This is the preferred option. However, the demand growth needs and potential changes in renewable generation will require further investigation to confirm the growth forecast figures on this 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, but with the laying of a new 185 mm² subsea cable rather than the like for like replacement in option 2. This cable has a higher initial cost however has the benefit over option 2 that it would cater for additional future growth with comparison against a 95mm² cable. This option retains single circuit security and potential risk of an interruption and the impact costs.

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

As in Option 2, the reduction in Probability of Failure and availability of the original circuit drives the NPV calculation which in this case, over 45 years is -£2,580 k.

This option was rejected as the additional capacity provided by the larger cable is not required and the option does not provide the best NPV.

6.4 Option 4: Augmentation with a similar 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 into the 11 kV network on Kintyre and Gigha.

This would provide enhanced security with two 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 Probability of Failure and availability of the original circuit drives the NPV calculation which in the case is -£2,440 k.

This option was rejected as the additional cost does not provide sufficient additional benefits to justify the additional cost over Option 2.

6.5 Option 5: Augmentation with a larger cable.

This option is similar to option 4 but utilising a 185 mm² cable instead of the 95 mm² cable. This would cater for additional potential growth, however on existing forecast growth levels this would not be necessary at this time.

This option, like option 4, provides N-1 security of supply against a subsea cable fault until the failure of the existing cable.

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

As in Option 4, the reduction in Probability of Failure and availability of the original circuit drives the NPV calculation which over a 45 year period is -£2,590 k.

This option was rejected as the additional capacity provided by the larger cable is not required and the option does not provide a better NPV than option 2.

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 mm^2 cables and would provide N-1 capacity against a subsea cable fault.

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 over 45 years is -£4,850 k.

This option was rejected as the higher cost does not provide sufficient 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 when considering the 6 investment options, as described below:

7.1 Summary of Costs

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
1. Do Minimum	£m	-	-	-	-	[redacted]	[redacted]
2. Replace	£m	[redacted]	-	-	-	-	[redacted]
3. Replace with larger cable	£m	[redacted]	-	-	-	-	[redacted]
4. Augmentation	£m	[redacted]	-	-	-	-	[redacted]
5. Augmentation larger cable	£m	[redacted]	-	-	-	-	[redacted]
6. Two new cables existing route	£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 2 to 5 on NPV over 45 years, of the options considered in the CBA, Option 2 has been selected as it meets all requirements whilst being the least cost and best NPV, as shown in Table 3 & Table 4.

Table 4 – Summary of NPV

Options	NPV After 45 Years (£m)
1. Do Minimum	-3.01
2. Replace	-2.43
3. Replace with larger cable	-2.58
4. Augmentation	-2.44
5. Augmentation larger cable	-2.59
6. Two new cables existing route	-4.85

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 11 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
11 kV subsea cable	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 11kV subsea cable between Kintyre and Gigha.

Due to the number of subsea cable faults in ED1 the approach 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 to be addressed. This approach considers the full subsea population within the generic CBA model to identify the appropriate circuits where intervention is required. In addition, recent stakeholder feedback regarding replacement of community wind turbines by 2027 has also been considered within the evaluation process.

This EJP covers the Kintyre - Gigha cable for which the monetised risk value was evaluated as £25,719 at the start of ED2 and without intervention will increase to £57,865 at the end of ED2. With the intervention proposed in this EJP the value of monetised risk will reduce to £13,913. The PoF is increasing significantly over ED2 and the consequences of failure are £4.777 million including £4.2 million to replace the cable on failure.

This EJP proposes Option 2 as the preferred option for intervention, replacing the existing cable with a similar sized cable at a cost of £[redacted]million.

CV Table	Asset Category	ED2 (£m)
CV7 Asset Replacement	HV Subsea Cable	[redacted]