RIIO ED2 Engineering Justification Paper (EJP)

Shetland Standby Project

Investment Reference No: 387/SHEPD/REGIONAL/SHETLAND

Contents

Definitions and Abbreviations

Acronym	Definition	Acronym	Definition
ANM	Active Network Management	SEPA	Scottish Environment Protection Agency
BESS	Battery Energy Storage System	SEU	Scheduled Energy Unavailability
CBA	Cost Benefit Analysis	SHEPD	Scottish Hydro Electric Power Distribution
CI	Customer Interruption	SHET	Scottish Hydro Electric Transmission
CML	Customer Minute Lost	SSEN	Scottish and Southern Electricity Networks
CT	Customer Transformation (DFES)	SC	Synchronous Condenser
DFES	Distribution Future Energy Scenarios	ST	System Transformation (DFES)
DG	Distributed Generation	SVT	Sullom Voe Terminal
DNO	Distribution Network Operator		
DSO	Distribution System Operator		
EfW	Energy from Waste		
EJP	Engineering Justification Paper		
ESA	Electricity Supply Area		
EV	Electric Vehicle		
FCO	First Circuit Outage		
FEU	Forced Energy Unavailability		
GD	Group Demand		
GIS	Geographic Information System		
GSP	Grid Supply Point		
GW	Gigawatt		
HVDC	High Voltage Direct Current		
IDP	Investment Decision Pack		
kW(h)	kilowatt (hour)		
LCT	Low Carbon Technology		
LPS	Lerwick Power Station		
LRE	Load Related Expenditure		
MDG	Mobile Diesel Generation		
MTTR	Mean Time To Repair		
MW	Megawatt		
NGESO	National Grid Electricity System Operator		
NINES	Northern Isles New Energy Solutions		
PEV	Pure Electric Vehicle		
PHEV	Plug-in Hybrid Electric Vehicle		
PPA	Power Purchase Agreement		
PSSE	Power System Simulation for Engineering		
PV	Photovoltaics		
RTS	Radio Tele-Switching		

1 Executive Summary

This Engineering Justification Paper (EJP) proposes the strategic investment required to prevent supply interruptions that could occur on the Shetland distribution system during system outages following implementation of the Shetland transmission link. It also incorporates the expenditure necessary to manage security of supply on the Shetland islands from the start of RIIO-ED2 until the Shetland transmission system and new Grid Supply Point (GSP) are in place. Together with the previously approved Shetland contribution, these will combine to fulfil our licence obligation, under Special Licence condition CRC2Q, to bring forward an enduring integrated plan for the Shetland islands.

There are currently over 13,000 distribution customers on Shetland. 2020/21 peak demand was 43.5 MW in winter. At present there is no interruption of supply to the Shetland islands as a result of a First Circuit Outage (FCO) as defined under P2/7, either as a result of planned or unplanned outages, because there is always additional generation running between Lerwick Power Station (LPS), Sullom Voe Terminal (SVT) and distributed generation such that the loss of any one generator, or a circuit/transformer fault, will not result in a blackout for the entire Shetland network. The existing combined network and generation arrangements provide security of supply such that island-wide blackouts have not been experienced in the last 30 years.

Our load estimates and Distribution Future Energy Scenarios (DFES) indicate that the Group Demand (GD) for Shetland is likely to increase above 60 MW by 2028/29 (potentially earlier) and Shetland will become Class of Supply D for Engineering Recommendation P2/7. This will require that for FCOs a minimum of 40.4 MW of demand is met immediately and the entire GD to be met within 3 hours.

In the absence of suitable standby arrangements, customers on Shetland will experience annual interruptions ranging from 4 days to 3 months on the basis of planned transmission outages for scheduled maintenance, and may experience additional interruptions for unplanned outages which, if they occur, are predicted to last from 1 day to a number of months, depending on the fault type.

Following optioneering and detailed analysis set out in this EJP and as detailed in SHEPD's 2020 Shetland Standby Recommendation, the proposed scope of works to deliver the security of supply requirements on the Shetland islands is as follows.

- Maintain an extension of existing security of supply arrangements from April 2023 until the new GSP and Shetland transmission system are available; expected to be early 2025.
- Transition the existing Lerwick Power Station from full duty to standby use.
- Procure reliable and innovative blackout avoidance equipment and services which will have the ability to maintain frequency, voltage and provide stability/short circuit infeed, maintaining supply, until LPS standby generation can be started.
- Contract for the provision of a new GSP on Shetland by NGESO / SSEN Transmission, connecting the distribution and transmission systems, and associated preparatory works.
- Facilitate several minor distribution network developments to facilitate the GSP connection and supply to / from the transmission system, including 33kV circuit breakers and underground cabling.

Our proposal also identifies the need for 'fault ride-through' functionality to manage any imbalances or interactions between the transmission and distribution systems immediately upon an outage occurring, driven primarily by the significant amount of transmission wind which may be connected. The final technical design is in development and will be determined through engagement with, and analysis by, SSEN Transmission and the results of future procurement activities. This will establish the specific technical solution required for the fault ride-through and its costs and, similarly, the blackout avoidance scheme which is also subject to further technical refinement and procurement processes.

Finally, our contribution towards the transmission link has been approved separately by Ofgem but is referenced in this paper for completeness. Changes to respective Licence and / or Price Control Financial Models will be required to implement this whole system contribution between ourselves and SSEN Transmission.

The estimated cost to deliver the recommended solution for RIIO-ED2 is £117.3m (excluding an estimated link contribution of £236m[1]). Following agreement by Ofgem[2] this will be subject to further refinement through procurement processes, follow up submissions and Ofgem decisions. The solution is dependent on the timing of delivery of the Shetland transmission system, with the wider system expected to be delivered during 2024 and the GSP to be completed by November 2024.

The solution delivers the following outputs and benefits.

- It is the lowest cost, compliant standby solution to secure Shetland demand, meeting P2/7 requirements now and with the ability to meet P2/7 requirements later in ED2 when demand is projected to increase from Class of Supply C to Class of Supply D.
- It will ensure that Shetland customers continue to experience an equivalent standard of security of supply to that currently in place.
- It provides greater future flexibility to transition to a lower carbon standby solution when one becomes available.
- It is modular in nature and can be augmented to meet future new connections and changing future demand and generation requirements for Shetland.
- It is expected to result in an innovative, first-of-a-kind configuration of technologies for blackout avoidance, provided by the market.
- Alongside the transmission link and associated contribution arrangements it forms part of an effective and comprehensive whole system solution for Shetland, and the solution overall results in the fulfilment of SHEPD's licence obligation at CRC 2Q to bring forward an enduring solution for the Shetland islands.

[1] Subject to change, further to confirmation of the final link cost value applied in the contribution calculation.

[2] Confirmation provided 14 June 2021

2 Investment Summary Table

Table 1 below provides a high level summary of the key information relevant to this EJP – Shetland Standby Project.

Table 1: Investment Summary

Name of Programme	Shetland Standby Project
Primary Investment Driver	Security of supply for Shetland, and the fulfilment of licence condition CRC 2Q.
Investment reference/mechanism or category	*387_SHEPD_REGIONAL_SHETLAND*
Output reference/type	As above
Cost	*Cost for the selected option is £117.3m* *(including pass-through and excluding link contribution[3])*
Delivery Period	*RIIO-ED2*
Reporting Table	The following Cost and Volume (CV) tables within the BPDTs correlate to the primary investment drivers for the asset category covered by this Engineering Justification Paper: • CV1: Primary Reinforcement • CV4: Transmission Connection Point Charges (TCPC) • C25: Shetland totex • C22: Shetland pass-through
Outputs included in RIIO ED1 Business Plan	**No**

Table 2: Summary of the Reporting Table

Reporting Table (£m)		**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**Total**
Totex	CV1 Primary Reinforcement	-	£1.69m	-	-	-	**£1.69m**
	CV4 TCPC	-	£0.2m	£0.58m	£0.58m	£0.57m	**£1.93m**
	C25 Shetland	£27.8m	£56.3m	£6.6m	£5.4m	£3.7m	**£99.8m**
Pass through	C22 Shetland pass through (£m)	£6.8m	£4.7m	£0.8m	£0.8m	£0.8m	**£13.9m**
	We highlight that the BPDT include full Shetland costs for the RIIO-ED2 period. This EJP addresses the standby assessment presented within BPDT C25 (of which Mott MacDonald carried out the technical assessment, and Baringa carried out the cost assessment). We note that the GSP charges levied on SHEPD by NGESO are included in the Transmission Connection Point Charge element of the Load Related Expenditure forecast for ED2, CV4. The wider 33kV network reinforcements for the GSP integration are included separately in the CV1 cost table.						

[3] Please refer to Ofgem's Decision on Scottish Hydro Electric Power Distribution's proposals to contribute towards proposed electricity transmission links to Shetland, Western Isles and Orkney for further information on the link contribution

3 Background Information and Analysis

Shetland is an archipelago in the North Sea located 170km north of mainland Scotland and is part of our licence area. The 2020/21 peak demand of Shetland was 43.5 MW in winter based on the DFES. The load forecast in DFES 2020 for System Transformation (ST) shows demand growth on Shetland increasing the winter maximum to 58.2 MW during RIIO ED2, and higher under other scenarios, and up to 72.2 MW in 2032/33. This load forecast is based on the historical demand trend, DFES and new connections activity.

It was recognised in 2010/11 that an enduring security of supply solution for Shetland should be sought, and a new obligation was placed in our licence, CRC 2Q, to require us to bring forward an integrated plan to manage supply and demand. We have made three enduring solution recommendations in response to the obligation: the original Integrated Plan (IP) in 2013, the NES recommendation in 2017, and the Whole System contribution recommendation in 2018. The IP and NES recommendations were rejected; however, the Whole System contribution recommendation was approved.

Our 2018 Whole System contribution recommendation set out that we would make a submission for associated standby arrangement allowances following confirmation of the Shetland Transmission link Needs Case. Ofgem approved the Needs Case for the Shetland Transmission link and our contribution towards that link. It is currently assessing the costs of the link project, confirming the need for standby and triggering the requirement for associated arrangements to be implemented.

We submitted our standby recommendation, *2020-12-23 SHEPD Shetland Standby Recommendation* and associated appendices including CBA, to Ofgem in December 2020. The 2020 standby recommendation is part of our Shetland submission in the context of the ED2 business plan, and is an accompaniment to the ***Scottish Islands annex (Annex 8.1),*** this EJP and our Uncertainty Mechanism proposals ***Uncertainty Mechanisms (Annex 17.1)***. It should be read in conjunction with these documents, which provide updates and refinements where available. We highlight that Baringa's CBA methodology and the ED2 CBA methodology are distinct - we can provide more explanation on this if required.

3.1 Existing 33 kV Network Arrangement

The existing 33 kV network topology for Shetland is shown in Figure 1 below. Shetland presently has an uninterrupted power supply for the first planned or unplanned outage (e.g. outage for maintenance or a network fault). It is presently not connected to the Great Britain (GB) transmission network, and we are the Distribution System Operator (DSO) operating the synchronous generation (installed capacity of 70.75 MW) which is owned by SSE Generation at LPS. This is supported by third-party, privately owned, generation at SVT with which we have a Power Purchase Agreement (PPA) in place. We are the Distribution Network Operator (DNO) for the Shetland Islands, the network operates at 33 kV, 11 kV and LV. In addition, there is Distributed Generation (DG) connected to the Shetland 33 kV, 11 kV and LV network (7 sites with a total capacity of 12.3 MVA – excluding microgeneration).

The majority of demand on Shetland is centred near Gremista / LPS and is supplied via the local Gremista Primary substation via three 33/11 kV transformers. There are three 33 kV circuits which supply the rest of the Shetland demand (two running north and one south), combined with interconnection at both 33 kV and 11 kV.

Figure 2 shows the Geographic Information System (GIS) snapshots of Gremista substation and LPS.

Existing generation at LPS and SVT provides a reliable full duty power supply to Shetland with redundancy to allow necessary maintenance of the engines whilst ensuring security of supply for the unplanned loss of the largest engine. LPS generation is connected at both 33kV and 11kV directly into the Gremista substation and local Primary substation respectively. SVT is a 33 kV connected customer and has a total of four gas turbines with a minimum of two running at any one time. No island-wide blackouts have occurred on Shetland in the past 30 years.

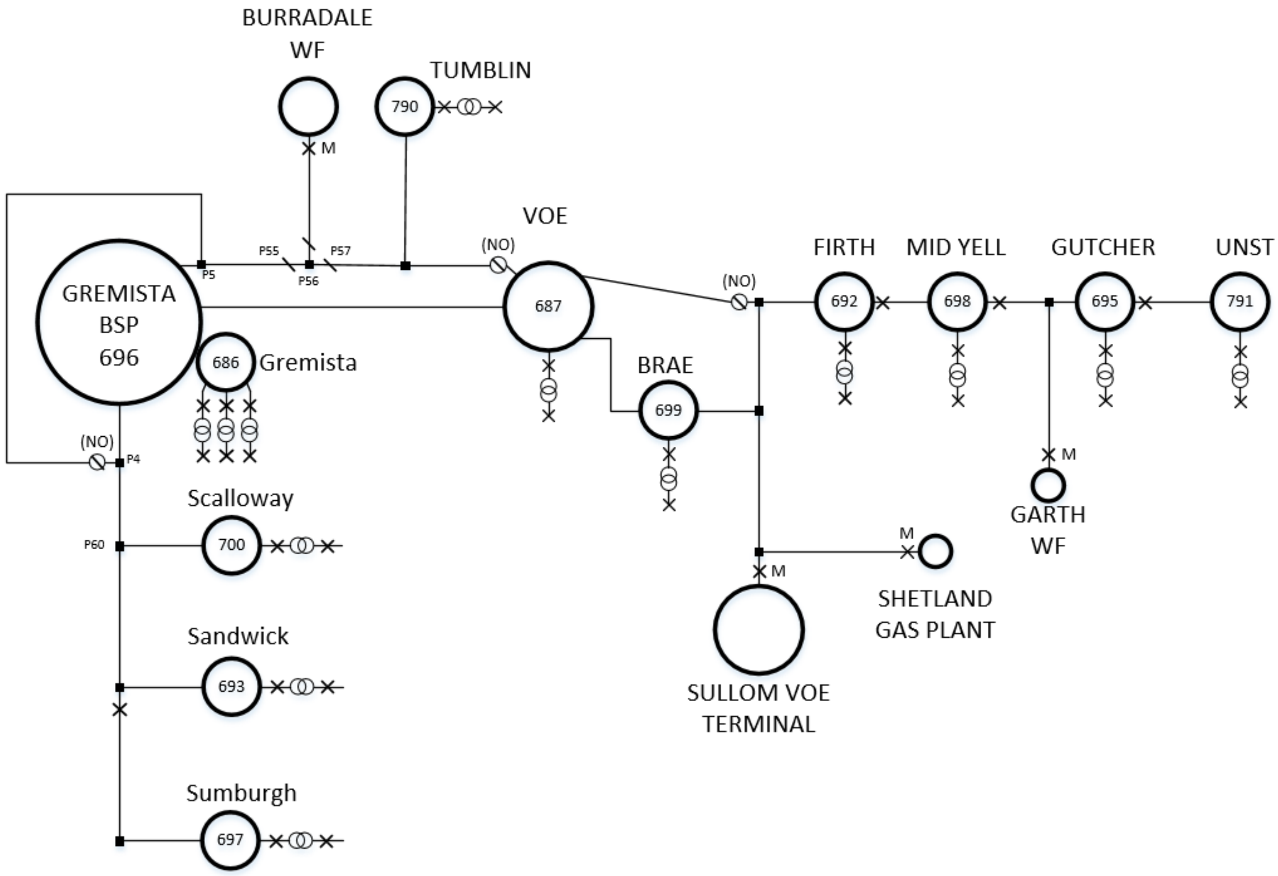

Figure 1: Existing 33 kV network on Shetland

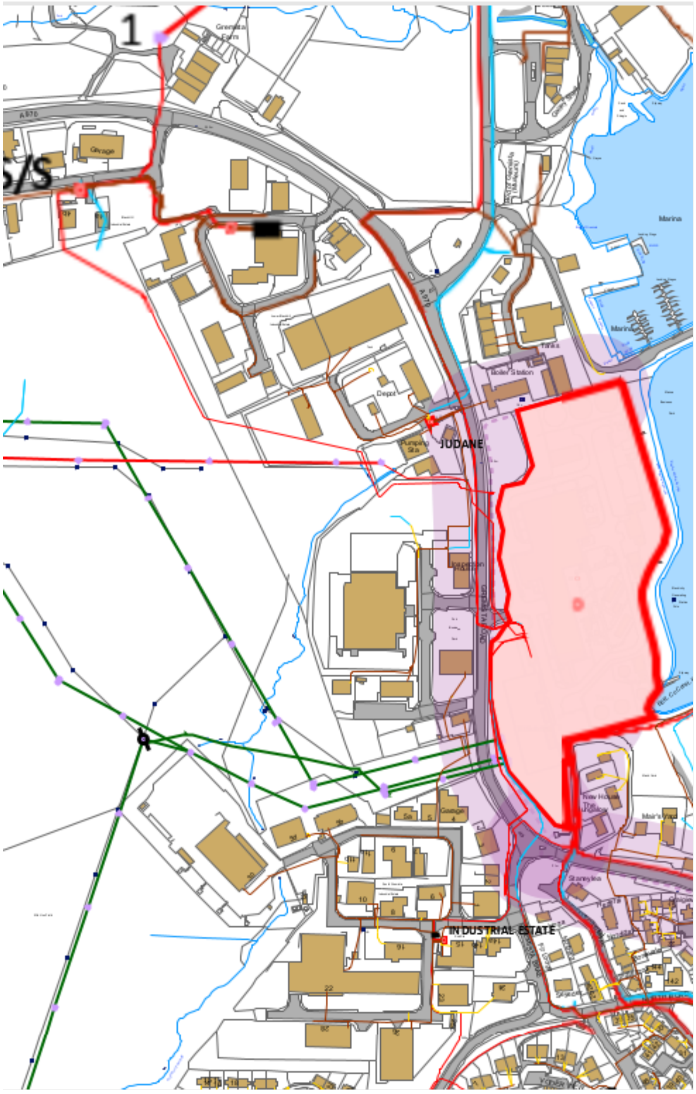

Figure 2: GIS Snapshots of Gremista Substation and Lerwick Power Station on Shetland

3.2 Load forecast in RIIO ED2

DFES 2020 demand forecast for Shetland shows that under both the ST and Consumer Transformation (CT) scenarios the maximum demand will increase considerably. The table below shows the extracted demand levels in MW from the DFES demand data for RIIO-ED2 and beyond. Demand levels vary between the two scenarios, increasing from 43.5MW in 2020/21 up to either 58.2 MW or 65.3 MW in RIIO-ED2 (2027/28) and up to either 72.2 MW or 83.5 MW in 2032/33, depending on the DFES scenario.

Table 3: Load Forecast for Shetland

Year	Shetland (DFES ST)			Shetland (DFES CT)		
	Winter (MW)	**Summer (MW)**	**Spring/Autumn (MW)**	**Winter (MW)**	**Summer (MW)**	**Spring/Autumn (MW)**
2020/21	43.5	31.7	36.1	43.5	31.7	36.1
2021/22	45.8	34.2	38.4	45.8	34.3	38.5
2022/23	48.0	36.6	40.7	48.4	36.8	41.0
2023/24	50.4	39.1	43.1	51.9	39.7	44.5
2024/25	52.1	40.8	44.8	55.2	42.0	47.7
2025/26	54.1	42.8	46.8	58.7	44.5	51.1
2026/27	56.1	44.8	48.8	61.9	46.9	54.1
2027/28	58.2	46.9	50.9	65.3	49.6	57.4
2028/29	60.4	49.1	53.1	68.6	52.3	60.5
2029/30	63.2	51.7	55.8	72.9	55.6	64.7
2030/31	66.1	54.5	58.7	77.0	58.9	68.6
2031/32	69.2	57.3	61.7	80.2	61.9	71.8
2032/33	72.2	60.0	64.6	83.5	65.0	75.2
Note: This demand table was produced in early 2021 following the release of updated DFES. Previous DFES demand data used for the SHEPD Shetland Standby Recommendation paper issued to Ofgem in December 2020 presented similar values.						

Most of the above increase in demand is associated with non-domestic developments on Shetland. Present new connections activity and stakeholder engagement support this forecast increase in demand.

Existing load factors are quite high for the Shetland total demand, this is a result of the domestic demand being better diversified by the Radio Tele-Switching (RTS) system and the type of commercial/industrial customers supplied having a reasonably constant peak demand throughout the year. This results in the peak spring/autumn and summer demand not reducing as much as usual when compared to the winter peak.

3.3 P2/7 Compliance Analysis

Existing Shetland Supply to 33 kV Network

At present there is no interruption of supply to the Shetland islands as a result of a First Circuit Outage (FCO) as defined under P2/7, either as a result of planned or unplanned outages. This is because there is always additional generation running between LPS, SVT and distributed generation (even during peak load and maintenance periods) such that the loss of any one generator, or a circuit/transformer fault, will not result in a blackout for the entire Shetland network.

The existing Group Demand (GD) for Shetland is 43.5 MW which makes it a Class of Supply C as per ER P2/7, over 12 MW and up to 60 MW. This requires that for FCOs a minimum of 29 MW of demand to be met within 15 minutes and the entire GD to be met within 3 hours. There are no Second Circuit Outage (SCO) requirements for a Group C class of supply. Shetland is presently compliant for P2/7 as for an FCO the entire Group Demand is immediately met, due to the modular nature of the generation arrangements, and the absence of a single point of failure. The existing combined network and generation arrangements provide security of supply such that island-wide blackouts have not been experienced in the last 30 years.

Future Shetland Supply to 33 kV Network

Our load estimates and DFES indicate that the GD for Shetland is likely to increase to 60.4 MW and 68.6 MW (DFES ST and CT respectively) by 2028/29 and Shetland will become Class of Supply D for ER P2/7. This will require that for FCOs a minimum of 40.4 MW of demand to be met immediately and the entire GD to be met within 3 hours. For SCOs there is no requirement until GD increases above 100 MW, when it does then it will require, within 3 hours, the smaller of: GD minus 100 MW and 1/3 GD to be supplied; followed by GD within the time to restore the planned outage.

As part of the Shetland HVDC Link project we have applied for a new 132/33 kV GSP (2x 132 kV circuits, 2 x 90 MVA 132/33 kV transformers) to be established at Gremista to supply the Shetland demand. This will provide a single circuit supply as for faults on the single HVDC cable or the converter station the supply will be unavailable. However, it will be available for planned and unplanned outages on any one of the two circuits/transformers. The Needs Case for the Shetland HVDC Link project has been approved by Ofgem along with our contribution (please refer to the Ofgem's decisions on this and our Shetland Standby Recommendation paper issued to Ofgem in December 2020 for more details).

In order to fulfil the security of supply requirements, as specified in P2/7 and stated above, it is therefore necessary to provide an alternative supply for the Shetland demand in the event of the Shetland HVDC Link or associated transmission network being unavailable.

3.4 Limitation with Existing Shetland Network

Once the Shetland HVDC Link is available, the entire Shetland GD will be at single circuit risk for the planned or unplanned outage of the HVDC cable or the associated converter stations. It will not be possible to start conventional standby generation and restore GD within 60 seconds or 15 minutes to meet either of the Group C or D requirements.

It is anticipated that the Shetland HVDC Link and associated transmission system will provide supplies to Shetland for approximately 96% of the time over a 20 year period, with the remaining 4% accounting for both Scheduled Energy Unavailability (SEU) and Forced Energy Unavailability (FEU). This is based on forced outage and failure rate data from SSEN Transmission for the HVDC system. Over 45 years, availability is anticipated to be around 95%. The predicted outage regime is included in Table 2.

Table 4: Predicted Shetland Transmission outage regime – SHET, 2020

Outage regime	Predicted frequency and duration
Planned outages	1% normal year; 2.6% average 45 years c.4 days per year regular scheduled maintenance c.14 days every 7 years – converter station monitoring system upgrade c.3 months every 20 years – converter mid-life upgrade
Forced outages	2.5% annual Predicted 1.87 individual annual outage events - duration dependent on which part of cable faults, and conditions when fault occurs: • Converter station: 1.65 trips/year; energy unserved 0.92 days per year • Cable: 0.22 trips/year; energy unserved 8.06 days/year Mean Time To Repair: • Land cable 20 days • Subsea cable 65 – 115 days
Overall	3 events / year; 18 days average / year; c.5% unavailability

A forced outage on the HVDC link without any standby equipment would result in a complete outage, causing an island-wide blackout of the supply to Shetland until the fault can be fixed. Evidence from other subsea cable faults confirms it could take several months to repair a fault on the HVDC submarine cable if delays occur due to bad weather and chartering vessels. A target Mean Time to Repair (MTTR) value of 115 days has been applied in modelling of HVDC interconnector availability representing a fault on subsea cabling (around 364km total) where there is restricted access due to weather, which based on SHEPD's own subsea cable experience, we do not consider to be a worst-case view in terms of MTTR; and around 251km of the Shetland HVDC cabling will be subsea. It is therefore essential that an alternative energy source is provided in the form of the Shetland standby solution.

3.5 Schedule 2: Site Specific Technical Conditions and Operational Arrangements

There is an Active Network Management (ANM) scheme operating on Shetland, implemented under the historical NINES project (Northern Isles New Energy Solutions). It is designed to allow DG to both connect and be managed appropriately to ensure system stability, e.g. if the Shetland demand drops too low then DG is constrained to ensure the synchronous machines can continue to operate and maintain the island frequency, voltage and stability. The ANM scheme will still be required in some form as part of the enduring arrangements, but will require modification to function when the distribution system is supplied from the Shetland HVDC Link, to implement the new standby arrangements considered in this EJP, and potentially also further modification if DG secures the ability to export onto the transmission system.

Technical consultants have carried out analysis to determine how to maintain continuous supply to Distribution customers without any blackout being experienced as a result of unplanned outages of the HVDC link or the wider Shetland transmission system. Analysis suggests that equipment will be required to i) enable the Distribution system to 'ride through' a transmission fault ('fault ride-through'), and ii) provide an instantaneous response of energy to meet demand that conventional generation technologies cannot, fulfilling this function while generation plant is started up ('blackout avoidance').

Fault ride-through functionality is expected to be deployed to manage any imbalances or interactions between the transmission and distribution systems immediately upon an outage occurring. In addition to their function of ensuring seamless continuation of supply, the blackout avoidance equipment and services are also expected to enable us to maximise the use of distributed generation *during* outages, and assumptions have been made on the size and cost of this equipment for the purpose of the analysis. The fault ride-through response and blackout avoidance system must be capable of absorbing the fault/power transfer from the transmission system to avoid creating issues on the distribution network, including the impact of significant wind generation output, and simultaneously keep the lights on for distribution-connected customers until the core standby solution starts up and takes over.

The specific technical solution, and the associated costs, required for the fault ride-through and, similarly, the blackout avoidance scheme are subject to further technical refinement and procurement processes. These will be determined through engagement with, and analysis by, SSEN Transmission, and future procurement activities. We are seeking these solutions, services and equipment from the market. These aspects are discussed in more detail in the following sections.

4 Load Flow Analysis

Load flow and contingency simulations were performed for the given Shetland network topology, load demand levels in winter, spring/autumn, and summer, and the corresponding DG dispatches for Shetland in the Power System Simulation for Engineering (PSS/E) models. The load flow results with the updated maximum DFES demand in winter are presented for the CT DFES scenario in 2028/29, as this is the most onerous case in terms of loading conditions on the Shetland network. The load flow results are applicable all years within the RIIO ED2 period after the HVDC link is programmed to be available.

4.1 Thermal Flow Analysis for Shetland Generation at LPS

First Circuit Outage (FCO) Analysis

Table 5: Thermal flow analysis for FCO

Demand Group	Season	Group Class	Contingency	Loaded Circuit / Transformer	MW Flow/MW Rating
Shetland GSP	Winter Max. Load	D	-	LPS Generation	71.60/70.75MW
Shetland GSP	Winter Max. Load	D	Outage on LPS Generator (B Station)	LPS Generation	71.77/58.00MW
Shetland GSP	Summer Max. Load	D	-	LPS Generation	53.96/67.25MW
Shetland GSP	Summer Max. Load	D	Outage on LPS Generator (B Station)	LPS Generation	53.96/54.50MW

For an FCO in winter, the existing LPS generation is overloaded and there is a 1 MW shortfall in generation margin during system intact. When considering spinning reserve for the loss of the largest generator, as shown above this results in a 14 MW shortfall in generation capacity. For the summer peak demand there is sufficient generator margin and spinning reserve, but planned maintenance of LPS generators would need to be considered - see SCO analysis below.

Prior to the HVDC link this shortfall in generation margin and spinning reserve is met by a PPA in place with SVT, which currently operates a minimum of two 18 MW gas turbines at any one time and provides between 4 MW and 15 MW of export to SHEPD.

Once the HVDC link is available it is intended to terminate the PPA with SVT. LPS is presently installing an 8MW/6MWh BESS which will provide spinning reserve and peak demand reduction. The proposed options in this EJP have been evaluated on the basis that they will need to provide for the remaining shortfall in generation margin and spinning reserve once on the HVDC link and the PPA with SVT ceases.

Second Circuit Outage (SCO) Analysis

Table 6: Thermal flow analysis for SCO

Demand Group	Season	Group Class	Contingency 1st outage	Contingency 2nd outage	Loaded Circuit / Transformer	MW Flow/MW Rating
Shetland GSP	Summer Max. Load	D	LPS Generator U8 (3.5 MW)	LPS Generator U24 (12.75 MW)	LPS Generation	53.96/54.50MW
Shetland GSP	Summer Max. Load	D	LPS Generator U22 (8.1 MW)	LPS Generator U23 (8.1 MW)	LPS Generation	53.98/54.55MW
Shetland GSP	Summer Max. Load	D	LPS Generator U3, U4, U5, U10 or U11 (1 of, 4.5 MW)	LPS Generator U24 (12.75 MW)	LPS Generation	53.97/53.50MW
Shetland GSP	Summer Max. Load	D	LPS Generator U13 or U14	LPS Generator U24 (12.75 MW)	LPS Generation	53.97/53.00MW

			(1 of, 5 MW)			
Shetland GSP	Summer Max. Load	D	LPS Generator U9 (5.8 MW)	LPS Generator U24 (12.75 MW)	LPS Generation	53.98/52.20MW
Shetland GSP	Summer Max. Load	D	LPS Generator U22 or U23 (1 of, 8.1 MW)	LPS Generator U24 (12.75 MW)	LPS Generation	54.00/49.90MW

Summer maximum demand is 16.3 MW lower than the winter peak in 2028/29 for DFES CT. For an SCO it is only possible to switch off the smallest LPS generator (U8, 3.5 MW) and still have sufficient generator margin and spinning reserve. If any of the other LPS generators are taken out of service (e.g. for planned maintenance) then for the loss of the largest LPS generator (U24, 12.75 MW) the remaining LPS generators would be overloaded.

As per the FCO analysis, prior to the HVDC link this shortfall in generation margin and spinning reserve is met by the PPA in place with SVT. This allows for LPS generators to be taken out of service for planned maintenance whilst ensuring sufficient generation for a SCO.

As noted, once the HVDC link is available it is intended to terminate the PPA with SVT, and LPS is presently installing an 8MW/6MWh BESS which will provide spinning reserve and peak demand reduction; therefore the proposed options in this EJP have been evaluated on the basis that they will need to provide for the remaining shortfall in generation margin and spinning reserve once on the HVDC link and the PPA with SVT ceases.

4.2 Voltage Level Assessment

With the intact network topology and under an FCO, voltage levels are in the limit of ± 6% on 33 kV bus sections at Gremista GSP. This is because the steady state reactive capability of the LPS generation is sufficient to operate and maintain the voltage within the target setting (1.03pu) along with the local 33/11 kV transformers automatic voltage control target settings (1.01pu – 1.03pu). Generation is switched out by LPS during lower demand periods to ensure the machines in service can operate within their limits whilst still maintaining the voltage, frequency and stability for Shetland.

The study results below show that additional Mobile Diesel Generation (MDG), LPS generators or storage / flexible services will be required under higher demand growth DFES scenarios, such as CT. It is possible for the existing LPS generators to provide the steady state reactive power required, but additional reactive power support will be required to provide voltage stability out on the 33kV network during faults.

Table 7: Voltage levels at Gremista GSP

Season	GSP Voltage Set Point	Group Demand	Total Generation	Study Scenario	High/ Low Voltage	Busbar Name
[-]	[p.u.]	[MW]	[MW]	[-]	[p.u.]	[-]
Winter Maximum	1.03	68.6	70.75	Intact Network	1.03/1.03/1.03	LERWCK 3A/3B/3C
Winter Maximum	1.03	68.6	58.00	LPS Generator U24 (12.75 MW)	1.03/1.03/1.03	LERWCK 3A/3B/3C
Summer Maximum	1.03	52.3	67.25	Intact Network	1.03/1.03/1.03	LERWCK 3A/3B/3C
Summer Maximum	1.03	52.3	54.50	LPS Generator U24 (12.75 MW)	1.03/1.03/1.03	LERWCK 3A/3B/3C

4.3 Summary of Core Standby Options Considered

4.4 Summary of Core Standby Options

The table below provides a high-level summary of the three core standby options under consideration along with the advantages and disadvantages associated with each. A more detailed description of each option is provided within the sub-sections which follow.

This section considers the core standby solution which would meet demand for the duration of any outage, complemented by the instantaneous response of the blackout avoidance and ride-through equipment and services. Flexible solutions are also being considered in this project to potentially reduce the amount of standby equipment, services and generation required, and a call for flexibility services on Shetland is currently open on our Distribution website in order to identify interest.[4]

'Do Nothing' is not included as an option as an HVDC link outage would, without standby arrangements, result in full island blackout on Shetland and supply interruptions to over 14,000 customers until the transmission network is restored or MDG is available, and is guaranteed to happen at least once a year for 4 days, driven by the link planned maintenance regime. This outcome is non-compliant with P2/7 and the D-Code and would require a derogation. High costs and time would be incurred in deploying significant capacity of MDG to Shetland as an alternative, which is typically less efficient and produces more emissions than larger plant. This outcome would also result in damage to customer confidence, with stakeholders perceiving that the investment made in the HVDC link solution had resulted in a worse standard of security of supply.

This EJP incorporates the Gremista GSP connection to ensure the assessment of the overall solution is comprehensive, and the most economic and efficient (e.g. the 33 kV circuit breakers and 33 kV cable connections) - an extract of the associated CV1 table has been included for reference. The associated GSP charges levied on SHEPD by NGESO are also included from the Transmission Connection Point Charges cost table (CV4).

In each scenario an uncertainty mechanism with a re-opener would be required to provide the opportunity to recover costs incurred to meet high demand growth and large new connections.

[4]https://www.ssen.co.uk/ConnectionsInformation/GenerationAndStorage/FlexibleConnections/CurrentCallsForFlexibility/

Table 8: Summary of reinforcement investment options[5]

Options	Description	Advantages	Disadvantages
Do Minimum. Standby Equipment with Existing LPS Used in Standby Mode	Convert LPS from full duty to operate in standby mode. Deploy additional blackout avoidance equipment to maintain frequency, voltage and provide stability/short circuit infeed until LPS standby generation can be started.	No blackout for HVDC link outage. Lower capital costs and deferral of LPS decommissioning costs. Medium delivery time. LPS is medium-speed engines, more efficient than high-speed. Utilisation of renewable DG to offset carbon during island mode running. Ability to flex to a low carbon solution when available.	Not low carbon generation (to extent not offset by renewables / storage / flexibility). Some of the larger LPS generators are slower to start therefore larger sized blackout avoidance equipment required.
1. Standby Equipment with Replacement of LPS for Standby Mode - High Speed Engines	Replace LPS with new high-speed engine-based standby generation. Deploy additional standby equipment to maintain frequency, voltage and provide stability/short circuit infeed until new standby generation can be started.	No blackout for HVDC link outage. Modern high-speed engines can be started quickly, therefore reduced size of blackout avoidance equipment. Utilisation of renewable DG to offset carbon during island mode running.	Not low carbon (presently no technically viable, economic low carbon alternative to thermal plant on the market). Higher capital cost than use of existing plant. Relatively long delivery time. High-speed engines are less efficient than medium speed. Less ability/more cost to flex to a low carbon alternative when available.
2. Standby Equipment with Replacement of LPS for Standby Mode – Medium Speed Engines	Replace LPS with new medium-speed engine-based standby generation. Deploy additional standby equipment to maintain frequency, voltage and provide stability/short circuit infeed until new standby generation can be started.	No blackout for HVDC link outage. Modern medium-speed engines can be started more quickly than the older LPS engines, therefore reduced size of blackout avoidance equipment. Medium-speed engines are more efficient than high-speed. Utilisation of renewable DG to offset carbon during island mode running.	Not low carbon (presently no technically viable, economic low carbon alternative to thermal plant on the market). Highest capital cost of technically viable short-list options. Long delivery time. Less ability/more cost to flex to a low carbon alternative when available.

[5] We highlight that Baringa's analysis considered the impact of procuring additional plant and services to accommodate high demand scenarios across the LPS, HS and MS options, and concluded that LPS remained the preferred option.

4.5 Do Minimum: Standby Equipment with Existing LPS Used in Standby Mode (**recommended**)

To provide a reliable standby solution for Shetland and to reduce the risk of supply interruptions to customers connected to the new Gremista GSP, this option proposes to retain LPS and convert it to standby operation. Engineering investigations have confirmed this is possible and LPS could be operated in standby for c.10 years.

If a blackout was to occur (e.g. for a fault on the HVDC link) then it is estimated to take 45 minutes to 1 hour to bring LPS generation online and restore supplies to the majority of Shetland, including network switching and balancing. In addition, to avoid customers being off supply while diesel generators at LPS are started, it is proposed to deploy blackout avoidance equipment to fill the gap in supply. This will consist of island mode stability equipment (to provide voltage support, inertia, and short circuit current) and energy storage/demand side response (to provide sufficient energy until generation is able to generate on to the system). In this option, it will require the following:

- Retain LPS and convert to standby operation for approximately 10yrs.
- Deploy blackout avoidance equipment/services based on peak demand from ST DFES scenario:
    - Island mode stability
    - Energy storage/demand side response.
- Uncertainty mechanism with a re-opener to provide opportunity to recover costs to meet high demand growth and / or large new connections.
- Monitor the market and emerging generator technologies for low carbon replacement for LPS.

Do Minimum will provide a viable solution without committing to the full lifetime of a new build diesel power station, therefore providing the value of future options to flex to a low carbon solution or second network links if/when available. In addition, the blackout avoidance equipment provides the opportunity to develop a hybrid solution utilising DG where possible to reduce the amount of diesel used.

Existing installed generation at LPS is sufficient to meet the energy requirements to the end of RIIO-ED2 based on the present DFES ST demand forecast which forms the basis for the costing of this option. This option is modular and can be augmented with MDG, additional engines or storage / flexible services at LPS if a higher demand forecast (e.g. DFES CT) or future large new connections materialise. The present basis for costs assumes a Synchronous Condenser (SC) and Battery Energy Storage System (BESS) will provide the blackout avoidance equipment/services based on DFES ST. An uncertainty mechanism with a re-opener is proposed to facilitate the incremental increase of additional generation and standby equipment if annual demand forecasts and new connections activity show a greater demand is likely. See ***Uncertainty Mechanism (Annex 17.1)*** *for more detail.*

It is proposed to connect the SC and BESS to the 33 kV network in order to maximise their effectiveness and reliability whilst minimising the connection costs and any associated reinforcements. Fault levels will need to be managed on the Gremista 11kV busbar, as per existing, to ensure that not all the generation at LPS is running at the same time as the SC and BESS. If this is deemed to not be possible then the Gremista 11 kV switchboard will need to be replaced.

Estimated capital cost (consultant CBA): [redacted][6]

[6] As noted at the beginning of the EJP, we have submitted a CBA produced by a consultant (Baringa) as part of our 2020 Standby Recommendation to Ofgem, which should be read as part of our business plan submission. Baringa's estimated costs for some aspects of the standby solution are lower than SHEPD's own estimates (i.e. energy storage, synchronous condenser). Baringa's estimated costs have been utilised in the 2020 Standby Recommendation CBA, while SHEPD's estimated costs have been utilised in the BPDT. Final cost estimates will be confirmed through the procurement process currently underway and confirmed to Ofgem in spring 2022.

4.6 Option 1: Standby Equipment with Replacement of LPS for Standby Mode – High Speed Engines

For a longer-term solution (>10 years) the full replacement of LPS would need to be considered. Following a market review by external consultants (Mott MacDonald) of the 'best' viable alternatives which are presently available, high speed diesels (reciprocating engines) were identified. High speed diesels have been selected due to the lower capital cost and overall NPV when compared to alternative options, including medium speed engines. The faster starting time of high-speed engines provides greater flexibility than the medium speed option (e.g. lower energy storage MWh requirement for blackout avoidance equipment).

Similar to Do Minimum, if a blackout was to occur (e.g. for a fault on the HVDC link) then it is estimated to take 30-45 minutes to bring the high speed engines online and restore supplies to the majority of Shetland, including network switching and balancing. Similarly, to avoid customers being off supply while diesel generators are started, it is again proposed to deploy blackout avoidance equipment to fill the gap in supply. This will consist of island mode stability equipment (to provide voltage support, inertia, and short circuit current) and energy storage/demand side response (to provide sufficient energy until generation starts up).

The following is required for this option:

- Install a new diesel power station (c.70MW) with high speed engines and decommission LPS.
- Deploy blackout avoidance equipment/services:
    - Island mode stability
    - Energy storage/demand side response.
- Uncertainty mechanism to recover costs to meet high demand growth and large new connections.
- Monitor the market and emerging generator technologies for low carbon replacement to high speed diesel engines.

Option 1 will meet the requirements for Shetland and the generation capacity installed is expected to have a 20-year lifetime. Present day prices for residual values of the generation plant have been used when considering earlier replacement, but this still results in a higher cost when flexing to a low carbon replacement after 10 years. Comparable benefits exist as for Do Minimum with regards to the opportunity to develop a hybrid solution - this is enhanced by the high speed engines due to their quicker start time resulting in more flexibility and less requirement for energy storage.

For the basis of the costs for this option the DFES ST demand forecast has been used to determine the number of new generators needed to meet the energy requirements to the end of RIIO-ED2. This option is also modular and can be augmented with MDG, additional generators or storage / flexibility services if a higher demand forecast (e.g. DFES CT) or future large new connections materialise. Once again, the present basis for costs assumes an SC and BESS will provide the blackout avoidance equipment/services based on DFES ST. It would require connection of the SC and BESS to the 33 kV network in order to maximise its effectiveness and reliability whilst minimising the connection costs and any associated reinforcements. Fault levels would need to be managed when planning the connection of the new diesel generators and they should be split between 11kV and 33kV connections, as per the existing LPS generators, to ensure that none of the existing switchgear will exceed its rating and require replacement.

An uncertainty mechanism with a re-opener would again be required to facilitate cost recovery associated with the incremental increase of additional generation and standby equipment if annual demand forecasts and new connections activity show a greater demand is likely.

Estimated capital cost: [redacted][7]

[7] See footnote 5.

4.7 Option 2: Standby Equipment with Replacement of LPS for Standby Mode – Medium Speed Engines

The 'next best' viable alternative identified, which is presently available, is medium speed diesels (reciprocating engines). This option ranks below high-speed diesels and LPS due to the higher capital cost and overall NPV. Although medium speed engines are more efficient, due to the expected running times the additional capex required is not justified over the lifetime. In addition, the longer starting time of the medium speed engines provides reduced flexibility (e.g. higher energy storage MWh requirement for blackout avoidance equipment).

If a blackout was to occur (e.g. for a fault on the HVDC link) then it is estimated to take 45 minutes to bring the medium speed engines online and restore supplies to the majority of Shetland, including network switching and balancing. Similarly, to avoid customers being off supply while diesel generators are started, it is again proposed to deploy blackout avoidance equipment to fill the gap in supply. This will consist of island mode stability equipment (to provide voltage support, inertia, and short circuit current) and energy storage/demand side response (to provide sufficient energy until generation starts up).

The following is required for this option:

- Install a new diesel power station (c.77MW) with medium speed engines and decommission LPS.
- Deploy blackout avoidance equipment/services:
    - Island mode stability
    - Energy storage/demand side response.
- Uncertainty mechanism to recover costs to meet high demand growth and large new connections.
- Monitor the market and emerging generator technologies for low carbon replacement to medium speed diesel engines.

Option 2 will meet the requirements for Shetland and the generation capacity installed is expected to have a 20-year lifetime. Present day prices for residual values have been used when considering earlier replacement, but this still results in a higher cost when flexing to a low carbon replacement after 10 years. Comparable benefits exist as with Do Minimum and Option 1 in terms the opportunity to develop a hybrid solution, though the medium speed engines offer a slower start time than high speed engines resulting in reduced flexibility and higher requirement for energy storage duration (MWh).

For the basis of the costs for this option the DFES ST demand forecast has been used to determine the number of new generators needed to meet the energy requirements to the end of RIIO-ED2. This option is also modular and can be augmented with MDG, additional generators or storage / flexibility services if a higher demand forecast (e.g. DFES CT) or future large new connections materialise. Once again, the present basis for costs assumes an SC and BESS will provide the blackout avoidance equipment/services based on DFES ST. It is proposed to connect the SC and BESS to the 33 kV network in order to maximise its effectiveness and reliability whilst minimising the connection costs and any associated reinforcements. Fault levels will need to be managed when planning the connection of the new diesel generators and they should be split between 11kV and 33kV connections, as per the existing LPS generators, to ensure that none of the existing switchgear will exceed its rating and require replacement.

An uncertainty mechanism with a re-opener is again proposed to facilitate the incremental increase of additional generation and standby equipment if annual demand forecasts and new connections activity show a greater demand is likely.

Estimated capital cost: [redacted] [8]

[8] See footnote 5.

5 Summary of Cost Benefit Analysis

This section of the report provides an overview for each reinforcement from the Cost Benefit Analysis (CBA) previously undertaken and submitted to Ofgem. This represents the output of the detailed exercise undertaken to support the recommended investment strategy and that is now summarised within this EJP.

5.1 CBA of Conventional Investment Options:

To demonstrate the circumstances that would justify the selection of each investment option, an example CBA has been produced for each.

The results of this financial analysis are described below:

5.2 Summary of Capital Costs

Table 9: Summary of capital costs of options

Options	Unit	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Do Minimum – Standby Equipment with Existing LPS Used in Standby Mode	£m	0	[redacted]	0	0	0	[redacted]
Option 1 – Standby Equipment with Replacement of LPS for Standby Mode – High Speed Engines	£m	0	[redacted]	[redacted]	0	0	[redacted]
Option 2 – Standby Equipment with Replacement of LPS for Standby Mode – Medium Speed Engines	£m	0	[redacted]	[redacted]	0	0	[redacted]

5.3 Cost Benefit Analysis Comparisons

Table 10: Comparison of CBA of options

Options	NPV After 45 Years (£m)
Do Minimum - Standby Equipment with Existing LPS Used in Standby Mode	-68.8
Option 1 – Standby Equipment with Replacement of LPS for Standby Mode – High Speed Engines	-87.4
Option 2 – Standby Equipment with Replacement of LPS for Standby Mode – Medium Speed Engines	-139.7

5.4 Volume on Preferred Option

Table 11: Summary of volumes on preferred option

Asset Category	Unit	2023/24	2024/25	2025/26	2026/27	2027/28	Total
LPS in Standby	#		1				1
Standby Equipment	#		1				1
33kV CB (Gas Insulated Busbars)(ID)(GM)	#		6				6
33kV UG Cable (Non-Pressurised)	km	3.1	3.1				3.1

6 Validate investment plans and benefits with Stakeholders

This section of the EJP describes the stakeholder engagement strategy that has been implemented to inform our RIIO-ED2 submissions, and more specifically the proposed investment for the Standby Supply for Shetland. This includes the engagement activities that have been undertaken, the stakeholder groups that have been approached, and the feedback that has been gathered from this stakeholder engagement.

The intention of this exercise was to identify the appetite from our stakeholders for us to carry out the investment described within this document during RIIO-ED2 to improve the condition of our network assets and the quality of supply for customers during ED2 and beyond.

6.1 Our RIIO ED2 Stakeholder Engagement Strategy

We recognise that thorough stakeholder engagement is a critical part of our preparation of our ED2 business plan. As such, an engagement plan has been implemented to gather feedback from a diverse range of stakeholders.

The key activity that has been progressed to date which has provided feedback relevant to our Shetland enduring solution ED2 plans is a Shetland stakeholder event focusing on our standby approach at a high level.

The virtual stakeholder and consumer engagement event was held on 9 December 2020 with a range of stakeholders including representatives from Scottish government, Shetland Islands Council, local developers, and other large demand customers.

A significant amount of stakeholder engagement has also been undertaken on the link contribution proposals, now approved, in the form of many bilateral meetings with local councils, the Scottish Government and island stakeholders, published materials, the CUSC modification process, and through Ofgem's own consultation on the approach.

6.2 Stakeholder Engagement to Date

- SEPA

Engagement has been undertaken with SEPA to confirm the need for standby generation, and to identify SEPA's views on the application of relevant environmental legislation. As the standby specification is finalised over the coming year, engagement will continue to ensure compliance as required.

- Shetland demand and distributed generation customers

Engagement with key demand and distributed generation customers is ongoing. Looking forward, engagement will be carried out to identify any material connections which may come forward in order to finalise the demand and generation forecasts, to ensure standby requirements are specified comprehensively.

Targeted engagement will also be required with specific customers to communicate specific new aspects associated with the connection to the Transmission system, including day-to-day operational arrangements and outage procedures, and any changes to the rules of the ANM scheme, as referred to in Section 4.6.

- Shetland Islands Council

Engagement has been held to date with the council on future energy plans for the islands alongside oil and gas majors under the Orion Clear Energy Project[9], the primary focus of which is the decarbonisation of oil and gas activities. The Project envisages other workstreams including the development of a hydrogen economy on Shetland, which may be relevant to future standby discussions. Further engagement will be undertaken with the local authority to share the standby proposals, to identify near- and medium-term energy requirements,

[9] Orion Clean Energy Project | Providing clean affordable sustainable energy for our future

to discuss how the standby and wider energy arrangements play a role in the islands' Net Zero strategy, and any collaboration that can be taken forward, including in relation to potential future standby solutions.

- The market

Engagement was undertaken with the market in 2020 on blackout avoidance technologies. The Pre-Qualification Questionnaire (PQQ) stage of the procurement process to identify and procure appropriate technical solutions to meet the blackout avoidance requirements (inertia and fast response power currently considered able to be met through use of synchronous compensation and energy storage) completed in October, and the associated Invitation To Tender (ITT) is underway. We have also included Shetland in a call for flexibility services to identify potential services which could displace or offset any aspects of the standby solution.[10] Further engagement with the market will progress in relation to the Fault Ride-Through technology, if required, in due course.

- SSEN Transmission

Engagement with SSEN Transmission has been ongoing since our work to develop the contribution proposals and has become regular following application to connect to the Transmission system. We are working with SSEN Transmission to develop the GSP and to analyse the technical characteristics presented by the future Shetland network arrangement driven by the T-D interactions. In particular, the impact of transmission-connected windfarms on our distribution network and the single link connection to the GB system. We are also working to develop the operational philosophies and technical specifications relevant to the Distribution-Transmission connection and operation of the respective networks on Shetland.

- Ofgem

Engagement has been held with Ofgem on the standby recommendation, and the Shetland content of our ED2 business plan. Specifically, it has been agreed with Ofgem that we will confirm cost updates to Ofgem on the blackout avoidance arrangements in spring 2022 as part of the Supplemental Questions process, once these are available through the procurement process currently underway. Engagement is now being sought with Ofgem on the licence and Price Control Financial Model / Handbook changes required to implement the contribution, and on the specific standby arrangements and costs.

6.3 Stakeholder Engagement Feedback

The following questions were put to our stakeholders which are relevant to our future management of the Shetland network. Below each question is a summary of the key feedback that was gathered from the stakeholder engagement exercises that are described above.

We invited feedback on questions around whether to prioritise maintaining the current level of security of supply for the islands, the ability of renewable generation to provide power during outages, and whether to utilise existing generation or procure, build and use new standby solution, reflecting on the potential impact on the cost on these decisions.

Stakeholders expressed unanimous support (100%) for maintaining the existing level of security of supply, very strong support for accommodating renewables during outages (89%), and strong support for utilising existing assets (69%).

Table 22: Stakeholder responses, Shetland standby event – December 2020

Poll Question	Poll Option	Count	Total Votes	Results
Do you agree with our proposed principles?	Yes	19	20	95%
	NO	1	20	5%

[10] https://www.ssen.co.uk/ConnectionsInformation/GenerationAndStorage/FlexibleConnections/CurrentCallsForFlexibility/

Poll Question	Poll Option	Count	Total Votes	Results
Could you give us a bit more information about why you chose your answer	Agree overall. Especially happy with the fact that renewables will be utilised as a backup option. Maybe hydrogen can be part of the backup option as well	1	7	
	The top priority dominates correctly. The further objectives are comparatively more equal.	1	7	
	Agree with the broad principles. More detail on how fossil fuel-based backup solutions would be assessed particularly accounting for emissions and cost of carbon	1	7	
	Clearly vital to have a 2024 capable solution for the short and medium term. Much more questions about long term	1	7	
	Resilience of the system following the loss of the connection to the mainland has been considered.	1	7	
	Enable development wider renewables opportunities	1	7	
	Resilience Hydrogen Innovative	1	7	
For Shetland's Future Standby solution, please select the one that best represents your views:	SSEN should prioritise maintaining the current security of supply for the islands at a slightly higher cost	17	17	100%
	SSEN should prioritise a slightly lower cost solution which would result in short duration (around 1 hr) occasional loss of supply	0	17	0%
For Shetland's Future Standby Solution, please select the one that best represents your views	Prioritise the ability of renewable generation to provide power during outages, at a slightly higher cost	17	19	89%
	Constrain renewable generation from providing power during outages, at slightly lower cost	2	19	11%
For Shetland's Future Standby Solution, please select the one that best represents your views	Utilise existing generation until 2030s at lower cost, then seek Net Zero options from the market?	11	16	69%
	Procure, build and use new standby solution until 2030s-40s at higher cost, then seek Net Zero options	5	16	31%

Are there any further issues that Stakeholders would like to discuss in relation to Shetland's Future Solution?

- How quickly could a modernised Lerwick Station be expected to start up in an emergency situation
- Any future power solution must maximise the potential of local renewable energy generation on the distribution grid and minimise constraint. Will this be a main part of your agenda?
- Need clarity on charges for grid access, in and out of standby scenario.
- Shetland also needs to replace diesel, petrol and marine fuel with clean energy. How can SSE use local wind energy be used to help this happen?
- We would be interested in understanding what provisions are being made for enabling new embedded renewable generation to be able to be added to the distribution network going forward?
- What are the implications for current renewable generators with a non-firm connection?
- What would happen in a Black Start scenario? Shetland would be at the bitter end of the UK network.
- Other HVDC network solutions to build in higher level of contingency
- If using existing generation for stand-by, will upgrades be done on existing plant?
- Lots, but they will beyond the capacity of today's time, how do we follow up with further enhanced engagement?
- Are you looking for demand side solutions to help grid stability?
- On the previous question - neither of the options appeared to say that the solution could go "Net Zero" today?

Are there any further issues that Stakeholders would like to discuss in relation to Shetland's Future Solution?

- Maps should include Orkney and Shetland
- Is the Shetland back up going to be discussed today?
- VWF output is ca. 450MW. Has the power been contracted to dedicated customers on the Scottish Mainland via the interconnector in addition to Shetland user needs
- SIC are developing an energy hub renewables strategy which could utilise all VWF output to generate green H2 & supply offshore hence contracted output question
- What about a Black Start scenario? Shetland would be at the bitter end of that. Is there resilience for Shetland there?
- The framing of all of these questions and any answers is clearly critically determined by the timeframe. Compromises in the short term but not for ever
- Apologies if I missed this point - please can you clarify the timescales for when you will be presenting the analysis and preferred solution to Ofgem?
- Shetland renewables energy hub could use all of power from VWF and also input via interconnector from mainland. Could this be an option
- Is there any new information on the estimated transmission cost to use the interconnector, and does that figure change if the power is used within Orion?
- Will third parties be given the opportunity to provide backup solutions through competitive process?

7 Deliverability

Our deliverability strategy describes the approach for 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 our ED1 performance to our target ED2 efficiency. We have also demonstrated that our direct resources 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, and we have further refined our bottom-up efficiencies and work plan phasing for our final submission through the ongoing development of our ED2 Commercial & Deliverability Strategy and engagement with our supply chain.

Our deliverability testing has identified a major strategic opportunity which is relevant to all EJPs.

- In ED2 we 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.

- The Commercial strategy will explore the creation of Work Banks (WB) and identify key constraints. The Load work will be the primary diver for a WB, supplemented by Non-Load work at a given Primary Substation. This approach will capitalise on synergies between the Load and Non-Load work, whereby the associated downstream work from a Primary Substation will maximise outage utilisation, enabling the programme to touch the network in a controlled manner with the objective of touching the network once. Where there is no Primary Load scheme to support the Non-Load work, these will be considered and packaged separately, either insourced or outsourced dependant on volume, size and complexity.

- Transparency with the Supplier in terms of constraints, challenges, outage planning and engineering standards will capitalise on efficiencies, supported by a robust contracting strategy.

Due to the new and innovative approach required for the Shetland Standby Project a dedicated project team has been established with relevant technical experts and governance from across our business. The experience and skills acquired from previous Shetland projects (such as NES and NINES) along with LCNI projects and the more recent deployment of a new BESS at LPS; lay the foundation for the delivery of the Shetland Standby project.

8 Conclusion

The purpose of this EJP has been to describe the overarching investment strategy that we intend to take during RIIO ED2 for the load, generation, and operation related investment for the Shetland Standby Project.

Three options have been described which could be carried out as a solution to this load, generation, and operation related reinforcement. The viability of each of these options depends upon the ability to obtain regulatory approval for Shetland regarding standby generation and supporting allowances. In addition to the existing analysis, we have carried out further technical studies, market engagement and tendering to update the CBA for the Final Business Plan submission.

Due to the nature of the Shetland Standby Project and uncertainties associated with future demand, it is proposed that an uncertainty mechanism with a re-opener is provided in RIIO-ED2 to allow the opportunity for later cost recovery if required. See our uncertainty mechanism proposals ***(A_17.1 Uncertainty Mechanisms)*** for further detail.

As detailed within Section 8, a holistic approach is taken when selecting the most viable option for each investment, where the primary and secondary investment drivers are assessed together within a Cost Benefit Analysis (CBA). This includes future network trend analysis and careful consideration of the financial, safety, and environmental implications of each investment option.

- Do Minimum: Standby Equipment with Existing LPS Used in Standby Mode
- Option 1: Standby Equipment with Replacement of LPS for Standby Mode – High Speed Engines
- Option 2: Standby Equipment with Replacement of LPS for Standby Mode – Medium Speed Engines

A CBA has been performed to identify the preferred option which represents the best value for network investment to customers and can be considered least regret. The viability of the specific solutions is dependent upon the given load forecast for the Gremista substation, the specific technical conditions and operational arrangements for generating equipment on sites, and whether the proposed reinforcements are being implemented or not.

The options listed above have also been assessed against three RIIO ED2 strategies including Lowest Viable Product (LVP), Maintain Network Asset Risk (MNAR), and Interruptions Incentive Scheme and Net Zero (ISS & NZ).

Additionally, as documented in our Shetland Standby Recommendation paper issued to Ofgem in December 2020, external consultants have carried out cost benefit analysis considering a range of sensitivities and assessment periods to determine the most economic and efficient solution (e.g. low, central and high demand scenarios).

Further stakeholder engagement exercises will be undertaken to gather feedback on our strategy and confirm this meets the needs of our stakeholders.

To provide a compliant and enduring standby supply for Shetland and to reduce the risk of supply interruption to customers connected to the Gremista substation, the following costs and volumes are proposed for delivery during RIIO ED2. The recommended investment for the Shetland Standby Project in RIIO ED2 is Do Minimum - Standby Equipment with Existing LPS Used in Standby Mode which will require the following costs and volumes to be delivered:

Table 33: Summary of Shetland RIIO ED2 BPDT costs

CV Table	Unit	2023/24	2024/25	2025/26	2026/27	2027/28	Total
CV1 Primary Reinforcement	£m		£1.7	0	0	0	**£1.7**
CV4 Transmission Connection Point Charges	£m		£0.2	£0.6	£0.6	£0.6	**£1.93**
C25 Shetland	£m	£27.8	£56.3	£6.6	£5.4	£3.7	**£99.8**
Total totex	£m	£27.8	£58.2	£7.2	£6.0	£4.3	**£103.4**
C22 Shetland Pass Through	£m	£6.8	£4.7	£0.8	£0.8	£0.8	**£13.9**

Note values based on BPDT C25 C22, CV1 and CV4, not on consultant CBA (see footnote 3) and do not include the contribution to the SSEN Transmission link.

Do Minimum has been recommended because it is the lowest cost, compliant solution to secure the Shetland demand, whilst also providing value by preserving future flexibility to transition to a lower carbon standby solution when one becomes available. The chosen option is modular in nature and can be augmented to meet future new connections and the changing future demand and generation requirements for Shetland.