Flexibility Services for High Utilisation Groups

ED2 Engineering Justification Paper

ED2-LRE-SPEN-002-CV1-EJP

Issue	Date	Comments
Issue 0.1	May 2021	Issue to internal governance and external assurance
Issue 0.2	May 2021	Reflecting comments from internal governance
Issue 0.3	Jun 2021	Reflecting assurance feedback
Issue 1.0	Jun 2021	Draft Business Plan submission
Issue 1.1	Oct 2021	Reflecting updated DFES forecasts
Issue 1.2	Nov 2021	Reflecting updated CBA results
Issue 2.0	Dec 2021	Final Business Plan Submission

Scheme Name	Flexibility Services for High Utilisation Groups		
Activity	Flexibility Services		
Primary Investment Driver	Thermal Constraints		
Reference	ED2-LRE-SPEN-002-CV1		
Output	Flexibility Services		
Cost	**SPM - £1.634m**	**SPD - £1.076m**	
Delivery Year	2024-2028		
Reporting Table	CV1		
Outputs included in ED1	~~Yes~~/No		
Business Plan Section	Develop the Network of the Future		
Primary Annex	Annex 4A.2: Load Related Expenditure Strategy: Engineering Net Zero Annex 4A.6: DFES		
Spend Apportionment	**ED1**	**ED2**	**ED3**
	£m	**£2.710m**	**£m**

Technical Governance Process

Project Scope Development

IP1(S)

To be completed by the Service Provider or Asset Management. The completed form, together with an accompanying report, should be endorsed by the appropriate sponsor and submitted for approval.
IP1 – To request project inclusion in the investment plan and to undertake project design work or request a modification to an existing project
IP1(S) – Confirms project need case and provides an initial view of the Project Scope
IP2 – Technical/Engineering approval for major system projects by the System Review Group (SRG)
IP2(C) – a Codicil or Supplement to a related IP2 paper. Commonly used where approval is required at more than one SRG, typically connection projects which require connection works at differing voltage levels and when those differing voltage levels are governed by two separate System Review Groups.
IP2(R) – Restricted Technical/Engineering approval for projects such as asset refurbishment or replacement projects which are essentially on a like-for-like basis and not requiring a full IP2
IP3 – Financial Authorisation document (for schemes > £100k prime)
IP4 – Application for variation of project due to change in cost or scope

PART A – PROJECT INFORMATION

Project Title:	Flexibility Services for High Utilisation Groups
Project Reference:	ED2-LRE-SPEN-002-CV1
Decision Required:	To approve procurement of flexibility services for high utilisation groups in SP Distribution and SP Manweb licence areas.

Summary of Business Need:

Flexibility services, where we contract with customers/aggregators to reduce demand or increase generation to avoid/manage network constraints, will play a key part in helping to manage the pace of the low carbon transition as we invest in the network to increase capacity to the levels our customers require to enable them to adopt electric vehicles and electric heat.

Flexibility services can help us defer or avoid investment in new network capacity, be deployed more quickly than other interventions, help provide quicker and lower cost connections, and help democratise and bring competition to the energy sector. In developing our intervention plans for RIIO-ED2, we have tendered for flexibility services for each capacity shortfall that requires an intervention, based on our modelling results. This was to understand the availability and cost of flexibility.

We plan to use flexibility services to defer major reinforcement schemes, delay reinforcements within the RIIO-ED2 period and to manage the hours at risk during delivery of some reinforcements. These plans are detailed in individual Load Related scheme papers. Where flexibility services are not yet available, we will continue to retender for flexibility before the reinforcement starts, as both the market and road to Net Zero further develop.

We also intend to use flexibility to manage 48 demand groups outlined in this paper where the forecast loading is approaching limits and flexibility can reduce the risk of network constraints – particularly under higher uptake scenarios. These are the network areas where demand forecasts are high with marginal exceedances over the network firm capacity. The network constraints in these areas depend on the forecast generation and demand being fully realised and the capacity exceedances are minimal and predicted to occur for a few hours in a year. Flexibility services can manage these high loadings through the RIIO-ED2 period, deferring potential investments associated with high uptake scenarios from RIIO-ED2 into RIIO-ED3.

Summary of Project Scope, Change in Scope or Change in Timing:

For the RIIO-ED2 period procure additional flexibility services:

- In SPD licence area – 11 HV and 5 EHV groups for a total of **75.10MW** at **£1.076m.**
- In SPM licence area – 27 HV and 3 EHV groups for a total of **99.64MW** at **£1.634m.**

The total scheme cost is **£2.710m** (in 2020/21 prices) with 100% contribution to be included in the RIIO-ED2 load related expenditure.

Expenditure Forecast (in 2020/21 prices)

Licence Area	Reporting Table	Description	Total (£m)	Incidence (£m)				
				2023/24	2024/25	2025/26	2026/27	2027/28
SPD	CV1	Primary Reinforcement	**1.634**	0.050	0.120	0.008	0.127	1.330
SPM	CV1	Primary Reinforcement	**1.076**	0.011	0.038	0.140	0.126	0.761
SPEN		**Total Expenditure**	**2.710**	0.102	0.195	0.183	0.290	2.131

PART B – PROJECT SUBMISSION

Proposed by	Ramesh Pampana	Signature	P. Ramesh	Date:	30/11/2021
Endorsed by	Russell Bryans	Signature		Date:	30/11/2021

PART C – PROJECT APPROVAL

Approved by	Malcolm Bebbington	Signature		Date:	30/11/2021

Contents

1 Introduction

Flexibility services, where we contract with customers/aggregators to reduce demand or increase generation to avoid/manage network constraints, will play a key part in helping to manage the pace of the low carbon transition as we invest in the network to increase capacity to the levels our customers require to enable them to adopt electric vehicles and electric heat. To meet our evolving customer needs, we are developing smarter, more flexible network solutions to help mitigate the need for traditional reinforcement and reduce costs for our customers. We recognise that resources connected to our networks could provide services to assist in key areas that have specific challenges during periods of network constraint. So, we are exploring markets for flexibility with new and existing customers who are able and willing to control how much they generate or who can control their demand.

Flexibility in RIIO–ED1 period: Within the RIIO-ED1 period, we have floated our first-ever flexibility tenders for 10 locations across both SP Distribution (SPD) and SP Manweb (SPM) licence areas for the years 2020-23 and procured flexibility services for a total capacity of 81MW in the SPM licence area.

Flexibility in RIIO–ED2 period: For the RIIO-ED2 period, we will continue to take the flexibility services route to signpost to the market providers about the flexibility requirement and locations where the need arises. Our network studies have identified the capacity requirement of 334MW/9MVAr across both licence areas at all distribution voltage levels. To this effect, we have issued tenders in September 2020 and May 2021 to procure flexibility services to explore the option of reducing/ deferring the need for reinforcement.

Flexibility services can help us defer or avoid investment in new network capacity, be deployed more quickly than other interventions, help provide quicker and lower cost connections, and help democratise and bring competition to the energy sector. In developing our intervention plans for RIIO-ED2, we have tendered for flexibility services for each capacity shortfall that requires an intervention, based on our modelling results. This was to understand the availability and cost of flexibility. We plan to use flexibility services to defer major reinforcement schemes, delay reinforcements within the RIIO-ED2 period and to manage the hours at risk during delivery of some reinforcements. These plans are detailed in individual Load Related scheme papers. Where flexibility services are not yet available, we will continue to retender for flexibility before the reinforcement starts, as both the market and road to Net Zero further develop.

We also intend to use flexibility to manage 46 demand groups outlined in this paper where the forecast loading is approaching limits and flexibility can reduce the risk of network constraints – particularly under higher uptake scenarios. These are the network areas where demand forecasts are high with marginal exceedances over the network firm capacity. The network constraints in these areas depend on the forecast generation and demand being fully realised and the capacity exceedances are minimal and predicted to occur for a few hours in a year. Flexibility services can manage these high loadings through the RIIO-ED2 period, deferring potential investments associated with high uptake scenarios from RIIO-ED2 into RIIO- ED3.

Summary of project scope:
For the RIIO-ED2 period procure additional flexibility services:

- In SPD licence area – 11 HV and 5 EHV groups for a total of 75.10MW at £1.076m**.**
- In SPM licence area – 27 HV and 3 EHV groups for a total of 99.64MW at £1.634m.

The total cost of the scheme is **£2.71m** (in 2020/21 prices) with 100% contribution to be included in the RIIO-ED2 load related expenditure.

2 Background Information

SP Energy Networks (SPEN) operates electricity distribution network in three of the UK's largest cities (Liverpool, Glasgow & Edinburgh) and three significantly large rural areas (North Wales, Scottish Borders and Dumfries & Galloway). SPD network area supplies over 2m customers and SPM supplies over 1.5m customers. Figure 2-1 shows the SPD and SPM licence areas.

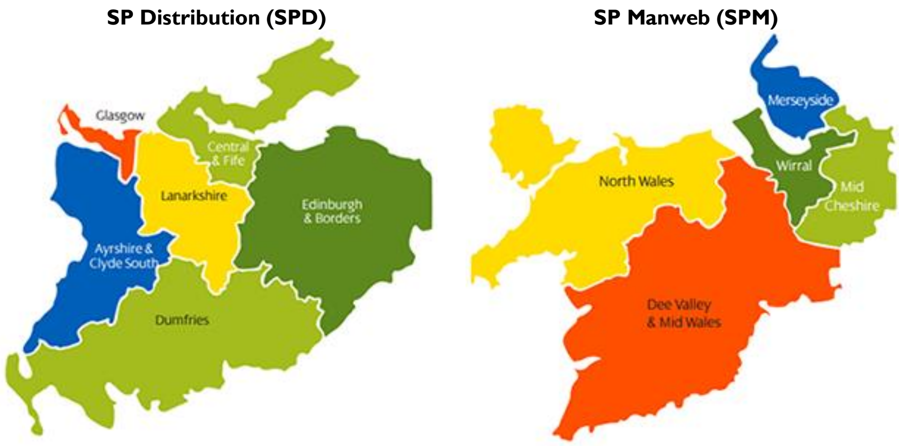


Figure 2-1: SPD and SPM electricity distribution network licence areas

The HV and LV distribution network across both licence areas comprises of over 85,000 HV/LV transformers, 45,000km HV circuits and 48,000km LV circuits.

3 Needs Case

Distribution networks will be key to facilitating the Net Zero targets by integrating increasing amounts of distributed generation, whilst accommodating the decarbonisation of the heat and transport sectors. The magnitude of this new demand and generation is well beyond what the distribution network is currently designed for. To tackle the climate emergency and deliver 2050 Net Zero (2045 in Scotland), the communities SP Energy Networks serve must:[1]

1. Electrify transport – up to 1.5m new electric vehicles (EVs) by 2030, rising to 3.4m by 2050.
2. Decarbonise heating – up to 0.9m new heat pumps (HPs) by 2030, rising to up to 3.1m by 2050.
3. Build more renewable generation – customer generation could triple in the next ten years.

The magnitude of these changes is significant and unprecedented – customer needs have not changed at this scale or rate before.

The Distribution Future Energy Scenarios (DFES) provide generation and demand forecasts to 2050 at a granular level, showing a range of credible future outcomes. Using our DFES scenarios and detailed network studies we have identified the network areas that may experience potential constraints due to increased loading in areas with limited network capacity (see section 3.2). These studies highlighted network areas with definite need for intervention, predicted to have high utilisation and limited network capacity to accommodate any of the future generation and demand. For those network areas, we included a wide range of solutions comprising flexibility services, conventional build and innovative solutions. Flexibility service tenders have been issued for these areas and received bids assessed to understand the availability and cost of market solutions to mitigate the network constraints.

[1] Source for decarbonisation values: SP Energy Networks, 'Distribution Future Energy Scenarios'.

Additionally, DFES projections and network studies have identified network areas with high utilisation where the constraints are likely to arise in the later years of the RIIO-ED2 period, particularly under the higher uptake scenarios. These are the network areas where demand forecasts are high with marginal exceedances over the network firm capacity. The network constraints in these areas depend on the forecast generation and demand being fully realised and the capacity exceedances are minimal and predicted to occur for a few hours in a year.

As the potential constraints are mostly dependent on the forecast volumes of generation and demand, the need for network reinforcement in these areas is closely tied to the rate of uptakes. For this reason, we are proposing to manage the high loadings at these sites using flexibility services. Flexibility services can manage these high loadings through the RIIO-ED2 period, deferring potential investments associated with high uptake scenarios from RIIO-ED2 into RIIO-ED3.

3.1 Forecast demand

Our DFES forecasts show that the demand forecast that by 2030 the networks' peak demand could by additional ca 15% in both licence areas under the highest scenario. The uptake of Low Carbon Technologies (LCTs) in the form of EVs and HPs is significant in both licence areas.. Smart charging associated with the EVs coupled with shift in customers usage patterns associated with domestic heating can inherently provide flexibility to the network. It is anticipated EVs could also support the network needs in the form of 'vehicle to grid', and the aggregation of EVs at customer level could provide significant shift in the network peaks.

Figure 3-1 and Figure 3-2 shows the geographical and technology split of the DFES demand forecast at 2030 and 2050 across the four DFES scenarios in SPD.

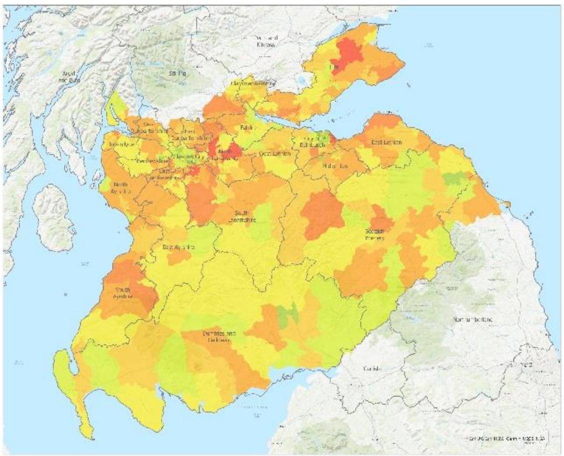


Figure 3-1. SPD DFES peak demand forecast at 2030

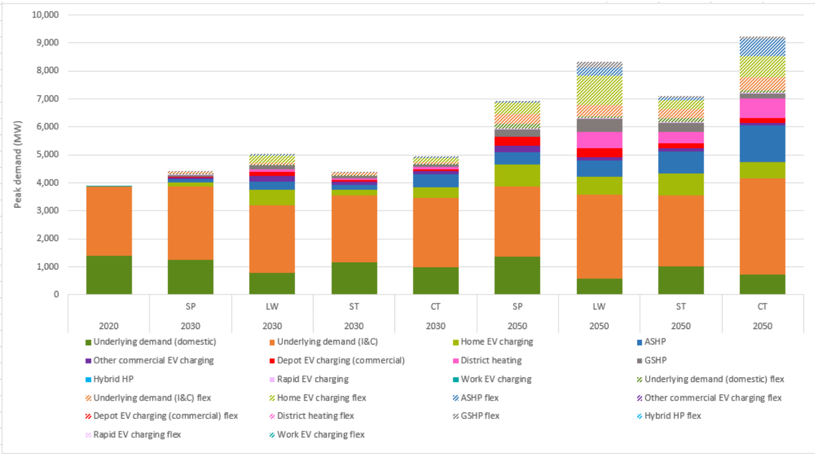


Figure 3-2. SPD DFES peak demand forecast per technology split at 2030

Figure 3-3 and Figure 3-4 shows the geographical and technology split of the DFES demand forecast at 2030 and 2050 across the four DFES scenarios in SPM.

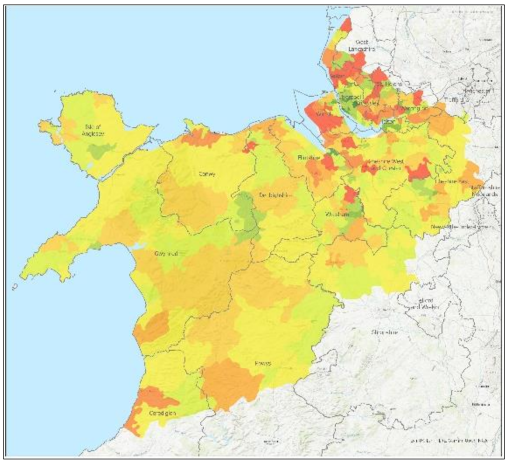


Figure 3-3. SPM DFES peak demand forecast at 2030

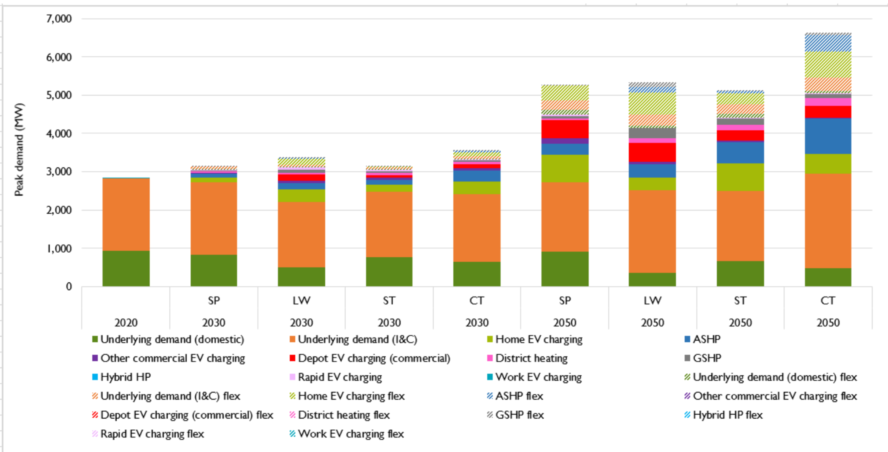


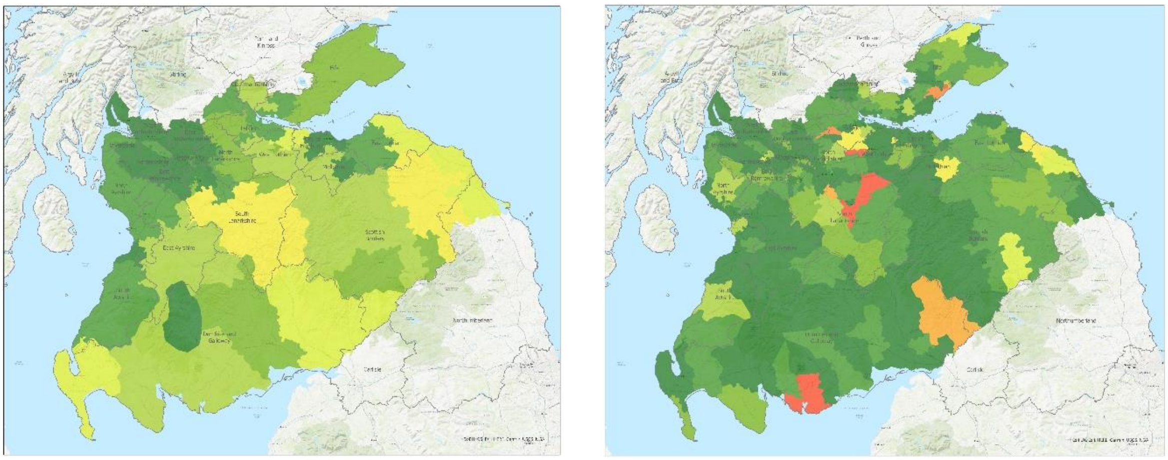
Figure 3-4. SPM DFES peak demand forecast per technology split at 2030

3.2 Forecast generation

In both SPD and SPM networks, growth in generation connections is expected to continue and indeed accelerate as UK generation decentralises to meet Net Zero targets. SP Energy Networks (SPEN) Distribution Future Energy Scenarios (DFES) forecast that by 2030 distribution generation could up to triple in SPD (reaching 6.9GW) and more than double in SPM (reaching 5.5GW).

All scenarios show a significant increase in generation. Most of the increase in capacity is expected to come from renewable sources like wind, PV and storage. Accommodating this low carbon generation, besides help achieving low emission targets, can act as flexible sources by responding to the demand changes on the network. Particularly, storage technology due to its ability act as both generation and demand is much better suited to provide flexible services.

Figure 3-5 and Figure 3-6 shows the geographical and technology split of the DFES generation and storage forecast at 2030 and 2050 across the four DFES scenarios in SPD.



GSP level forecast

Primary level forecast

Figure 3-5. SPD generation forecast for 2030

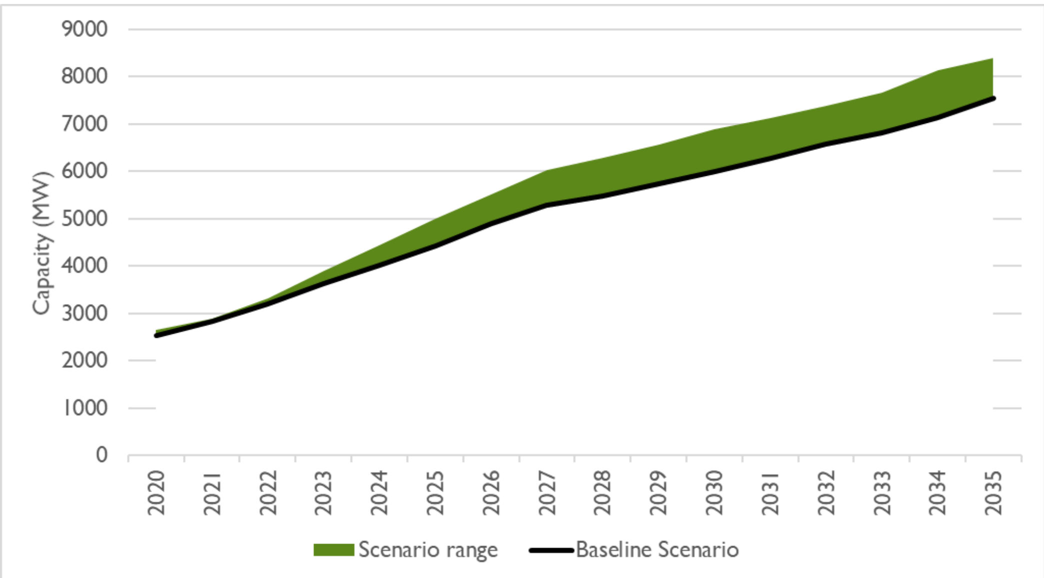
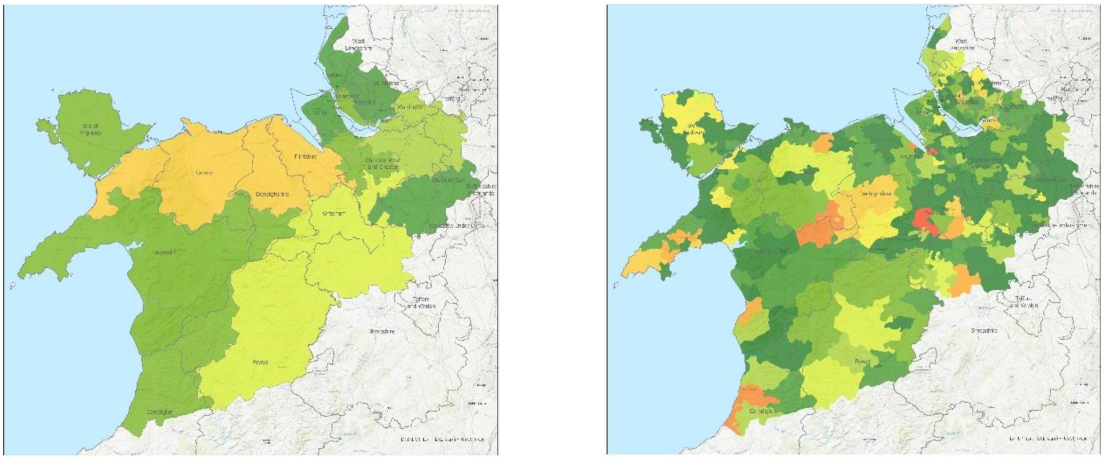


Figure 3-6: SPD range of Net Zero compliant distributed generation forecasts

Figure 3-7 and Figure 3-8 shows the geographical and technology split of the DFES generation and storage forecast at 2030 and 2050 across the four DFES scenarios in SPM.



GSP level forecast

Primary level forecast

Figure 3-7. SPM generation forecast for 2030

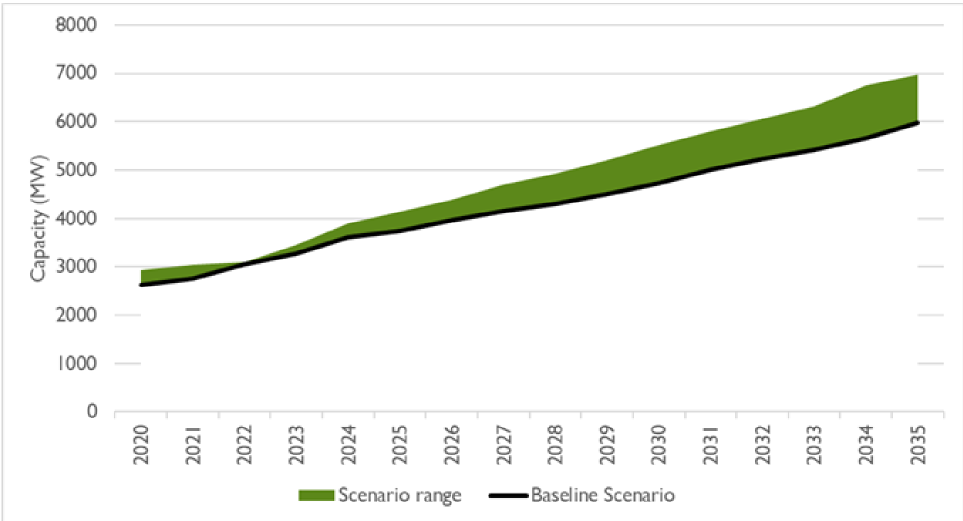


Figure 3-8: SPM range of Net Zero compliant distributed generation forecasts

3.3 Baseline View

Figure 3-9 and Figure 3-10 shows the demand and generation forecast under our Baseline View for the RIIO-ED2 period for both licence areas. Both demand and generation are expected to increase over the RIIO-ED2 period; demand is expected increase by 297MW in SPM area, 417MW in SPD area. The generation volumes are forecast to increase by up to 1.84GW in SPM and 3.12GW in SPD areas.

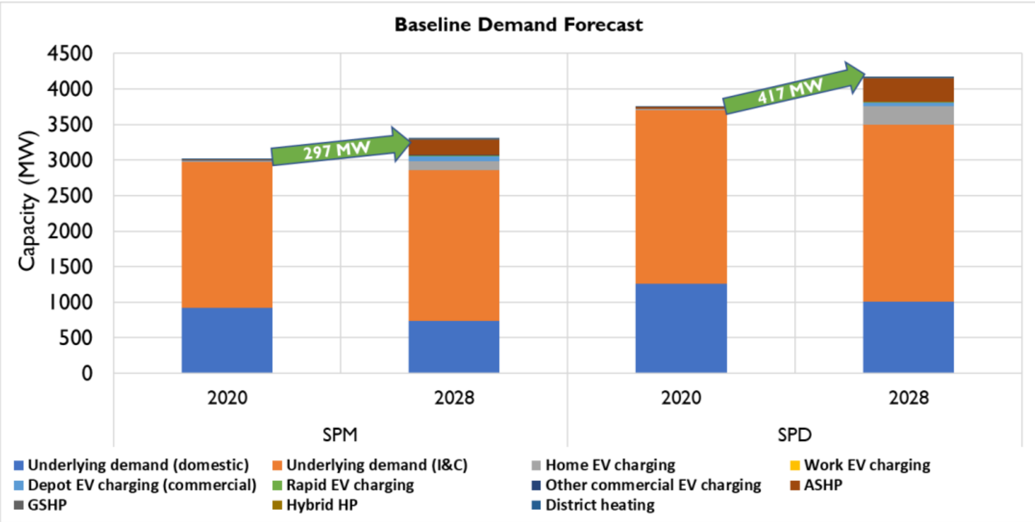


Figure 3-9: Baseline peak demand forecasts

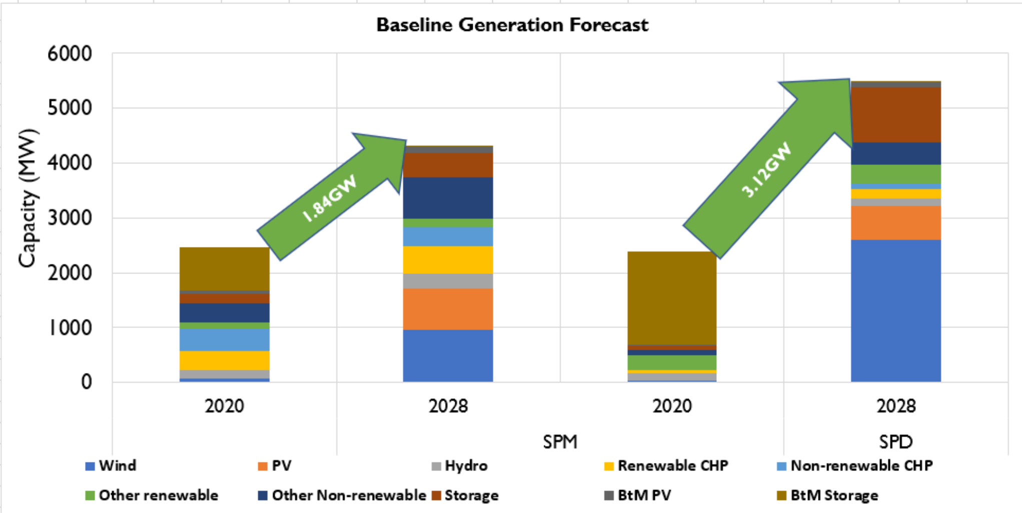


Figure 3-10: Baseline generation forecasts

3.4 Forecast constraints

Figure 3-11 and Figure 3-12 show the utilisation bands of the network groups at the end of RIIO-ED1 (2023) and RIIO-ED2 (2028) periods due to the forecast demand and without considering any planned interventions. The figures indicate the increased utilisation of the network groups as they move towards the high utilisation bands due to the forecast demand growth.

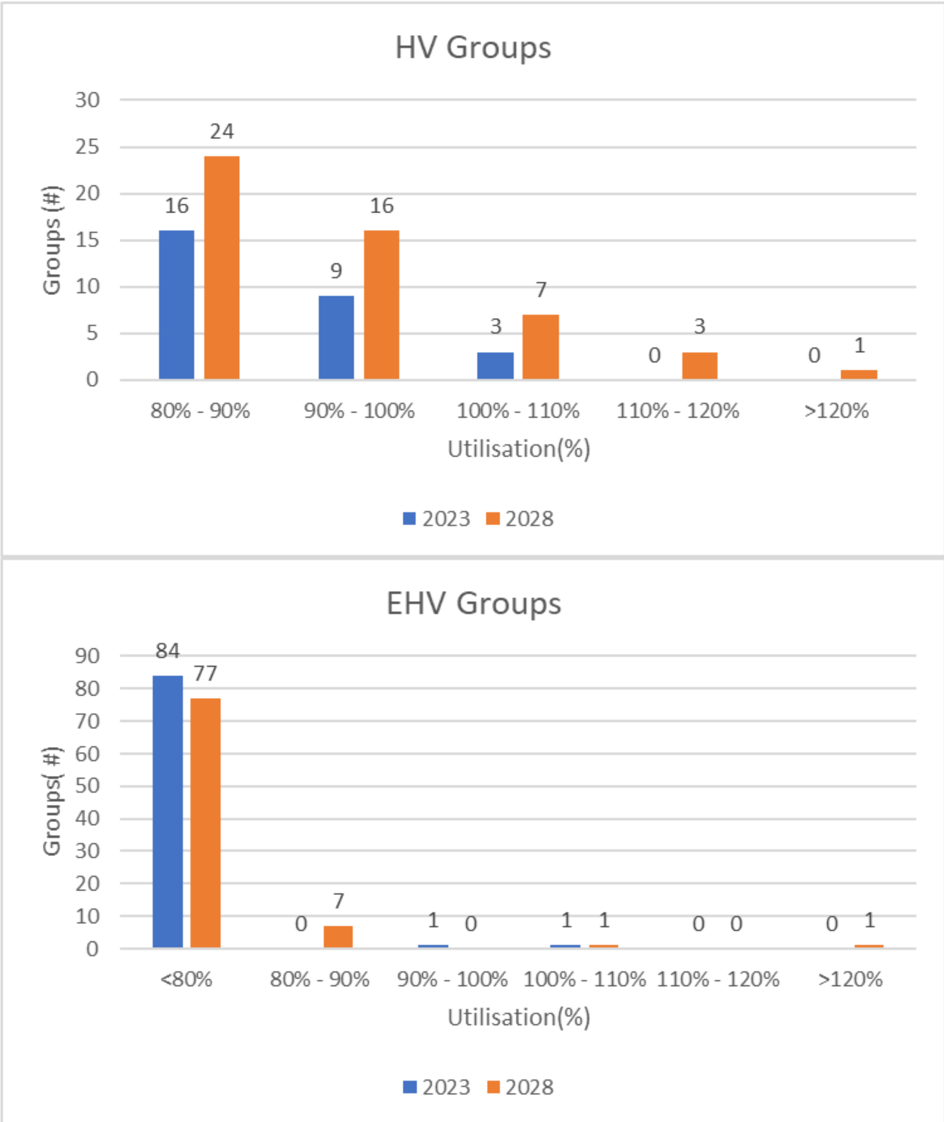


Figure 3-11. SPD network groups utilisation bands

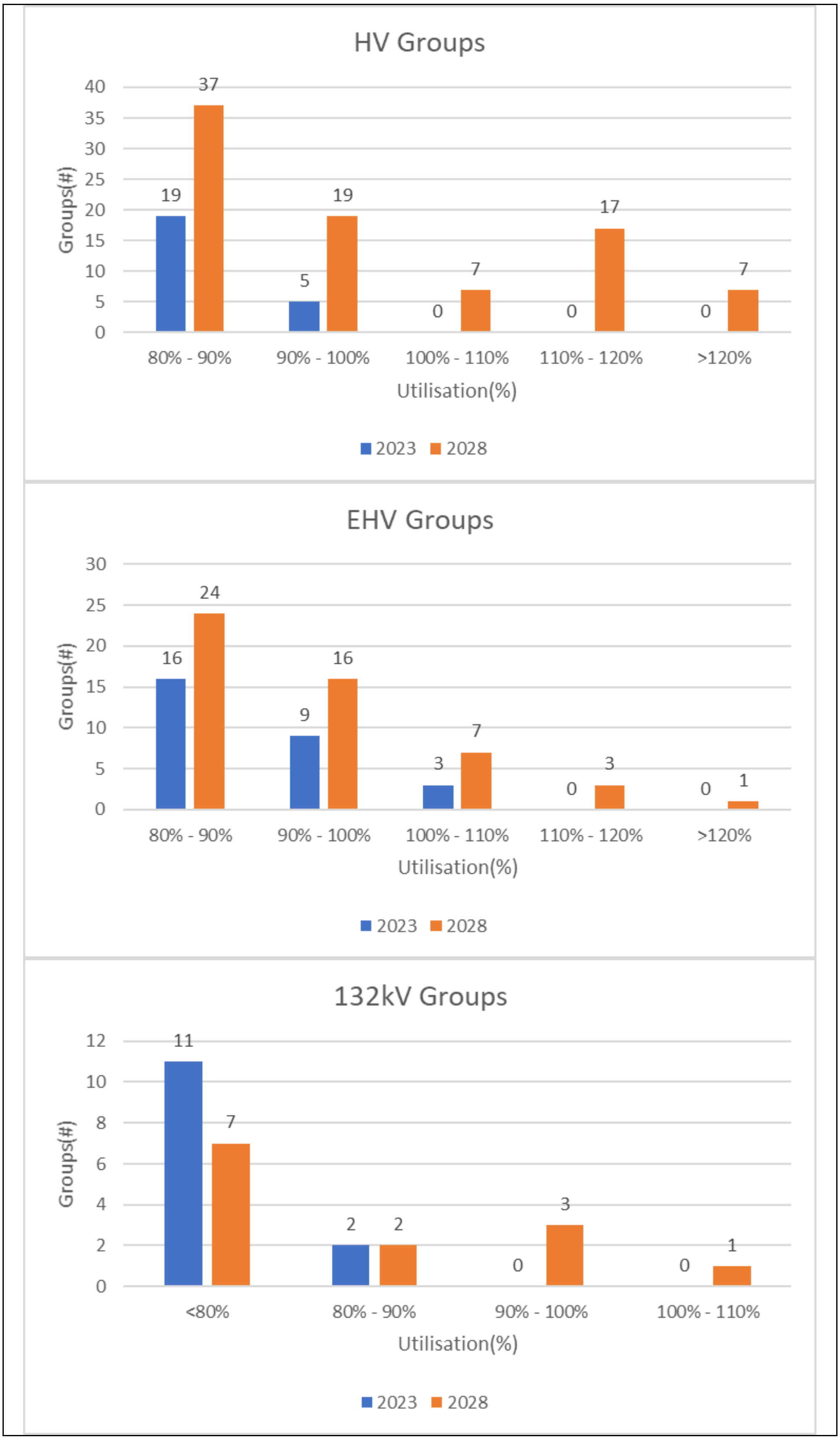


Figure 3-12. SPM network groups utilisation bands

4 Optioneering

Table 4.1 shows a summary of the options considered for the scheme. The baseline option represents the lowest cost conventional option, i.e. the minimum level of intervention without application of innovation.

Table 4.1. Longlist of solution options

Option	Description	Status	Reason for rejection
(a)	Do nothing	Rejected	Would lead to exacerbated network constraints (thermal / voltage). In areas where there is limited thermal / voltage headroom for new connections, this can prevent the low cost and timely connection of low carbon technology uptake onto the network.
(b)	Intervention plan using only Energy Efficiency	Rejected	Discounted due to lower cost effectiveness (peak MW reduction per £) and the number of individual interventions required across the wide area supplied by this network.
(c)	Conventional reinforcement to mitigate network issues	Shortlisted as **Baseline**	
(d)	Reinforcement deferral using flexibility services	Shortlisted as **Option 1**	

5 Detailed Analysis & Costs

The network thermal constraint during the most onerous outage was identified and time profile-based simulations (17,520 half-hourly simulations/year) were performed considering the historical half hourly measured Supervisory control and data acquisition (SCADA) data at primary substation overlaid with the DFES demand forecasts for each year through the RIIO-ED2 price control period. These studies identify the risk in terms of the thermal capacity exceedances with the forecast demand, the anticipated annual hours at risk and risk window of the constraint. The half-hourly studies performed for years starting from 2024 through 2028 determined the risk hours and the capacity required to overcome the constraint by using flexibility services.

Figure 5-1 shows a typical daily demand curve pattern plotted for the half-hourly interval for the entire day, (48 half-hour periods) for a network group with firm capacity of 10MVA. As observed, the demand exceeds the network firm capacity during the evening (tea-time) peak. The exceedance (overload) is ca 1MVA for an overload duration of the three hours.

Our network studies included half-hourly power flows performed for each of the network group. The perspective half-hour demands are compared against the firm capacity[2] of the group for each year starting from 2024 through 2028. This assessment provides a more granular view of the network capacity, better reflecting the in-year requirements due to the forecasts. The exceedances over the group's firm capacity are quantified to identify the anticipated time of risk on the network, the duration

[2] Firm capacity is the group's maximum demand that can be secured under the loss of network asset(s) and calculated as per EREC P2/7.

of the risk (overload) as well as the additional capacity required to alleviate the prospective thermal constraints on the network.

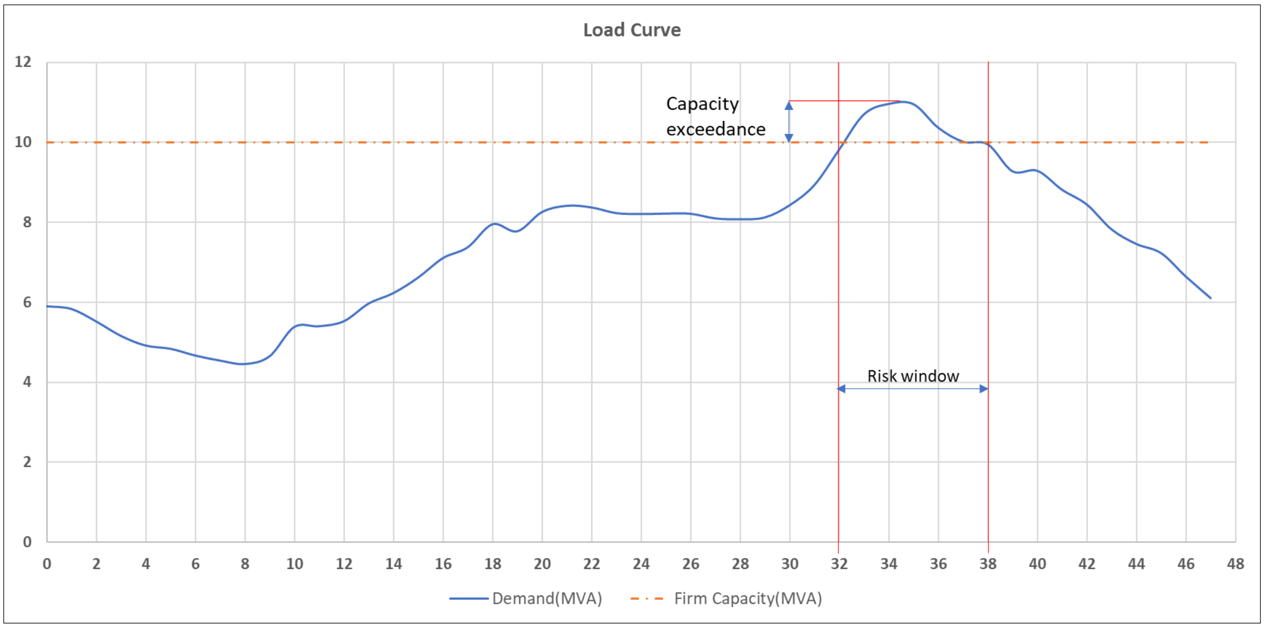


Figure 5-1. Example of group demand curve showing exceedance

5.1 Proposed Option (Option 1) – Flexibility Services

The proposed solution is to procure flexible services for the low risk and high utilisation sites in both SPD and SPM licence areas for the RIIO-ED2 period. This solution addresses the prospective network constraints due to the forecast demand/generation and potentially defer the need for conventional network reinforcements until and at least beyond the RIIO-ED2 period. The flexible services can help manage and address the capacity shortfalls at lower costs until the need for conventional reinforcement is established, better reflecting the in-year growth of demand and generation in the network.

The full list of sites, risk hours and the flexible capacity requirements for both licence areas are provided in Appendix 10 and 2. Table 5.1 summarises the capacity requirements for both licence areas.

Table 5.1. Flexible capacity requirements

Licence area	Voltage Level	Sites (#)	2024	2025	2026	2027	2028	Total capacity
SPD	HV	11	1.62	2.41	3.55	10.65	22.57	75.10
	EHV	5	3.75	4.72	6.18	6.19	13.48	
SPM	HV	27	-	0.10	3.81	13.95	30.52	99.64
	EHV	3	-	-	2.85	11.95	36.46	

5.1.1 Flexibility service products

The Energy Networks Association (ENA)'s Open Networks project developed four types of flexible service products the Distribution Network Operators (DNOs) can use dependent on the network needs. The product types and the particulars of each of the product type is given in Appendix 3.

For all the shortlisted sites, the 'Secure' products was chosen where flexibility services are requested to manage the network constraints (typically meeting the peak demand) and effectively managing the network loading within the firm capacity in the event of a network outage. For this product, contracts are to be placed with the service providers indicating the duration of the need (i.e., service window, typically winter / summer seasons) and the maximum capacity requirement, based on the forecast constraints. Considering the example in Figure 5-1, this would contract for at least the level of capacity exceedance using either generation turn up or demand turndown for the duration of the risk window.

5.1.2 Risk of under-procurement

The flexibility services are market-based solutions to address the network needs and there is an inherent risk of under-procurement due to several reasons. This could be due to:

1. No flexibility service providers available in the network area of need.
2. The markets not able to provide the required service/ product type.
3. Insufficient capacity available compare to the network needs.
4. The cost of service / product type is too high to procure.

Considering the risk, it is proposed that flexibility service tenders are run frequently (bi-annually / annually), simultaneously re-assessing the network needs. This would help in both refining the network changing needs as well as the flexibility services market would evolve with new technologies and competition can drive the services costs down.

5.1.3 Flexibility vs reinforcement

Due to the uncertainty associated with how the system will evolve in the future, uncertainty around how the forecasts materialise etc, flexibility is a valuable option. Flexibility solutions can efficiently, economically and with shorter timescales manage the network needs.

5.1.4 Flexibility costs

The flexibility services for the selected sites are costed using an bid price from the May 2021 round of SPEN tenders. Table 5.2 shows the yearly costs of flexible services across both licence areas.

Table 5.2. Flexible capacity costs

Licence area	Voltage Level	2024	2025	2026	2027	2028	Total Cost
SPD	EHV	0.002	0.002	0.002	0.004	0.065	1.076
	HV	0.011	0.038	0.140	0.126	0.761	
SPM	EHV	-	-	0.004	0.054	0.709	1.634
	HV	0.050	0.120	0.004	0.073	0.621	

5.2 Baseline Option – Portfolio of Traditional Solutions

This option considers traditional network reinforcements at these highly loaded sites. For each of the constrained network sites, the most feasible and economic conventional build scheme is costed. Table 5.3 shows the total cost of the schemes for these sites in both SPD and SPM.

Table 5.3. Conventional build scheme costs

Licence area	Voltage Level	No of sites	Cost (£m)	Total Cost (£m)
SPD	HV	11	22.506	33.808
	EHV	5	11.302	
SPM	HV	27	35.000	45.500
	EHV	3	10.500	

Total cost	**79.308**

5.3 Options Cost Summary Table

Summary of the costs for each of the evaluated options is presented in Table 5.4.

Table 5.4. Cost summary for considered options

Options	Summary	SPD(£m)	SPM (£m)	SPEN (£m)
Baseline	Conventional reinforcement	33.808	45.500	79.308
Option 1	Network reinforcement deferral using flexibility services	1.076	1.634	2.710

Derivation of costs for these options are based on the SPEN RIIO-ED2 Unit Cost Manual for intervention. This is based on bottom up cost assessment of the components of activity detailed within the RIGs Annex A for the above activities, SPEN's contractual rates for delivery, market available rates and historic spend levels.

6 Deliverability & Risk

6.1 Preferred Options & Output Summary

The adopted option represents an innovative solution of managing the prospective network constraints in the high utilisation network areas, thereby reducing / deferring the need for a conventional reinforcement beyond the RIIO-ED2 period.

6.2 Cost Benefit Analysis Results

A cost benefit analysis (CBA) was carried out to compare the NPV of the options discussed in the previous sections. Considering the lowest forecast capital expenditure, the proposed option has the lowest total NPV and represents the lowest-cost option when losses and other operational costs are included in the analysis. Based on the outcome of the CBA, the proposed option is to option 1. The summary of the cost benefit analysis is presented in Table 6.1. The full detailed CBA is provided within 'ED2-LRE-SPEN-002-CV1-CBA – Flexibility Services for High Utilisation Groups'.

Table 6.1. Cost benefit analysis results

Options considered	Decision	Comment	NPVs based on payback periods, £m (2020/21 prices)			
			10 years	20 years	30 years	45 years
Baseline – Conventional reinforcement: replant / replace network assets to create more thermal headroom	Rejected	The conventional reinforcement solution does not offer cost benefit compared to the innovation solution				
Option 1- Reinforcement deferral using flexibility services	**Adopted**		£15.53	£13.62	£12.33	£11.11

6.3 Cost & Volumes Profile

Table 6.2 shows the breakdown of expenditure for the proposed scheme (in 2020/21 prices) and the cost incidence (in 2020/21 prices) over the RIIO-ED2 period is shown in Table 6.3. The total cost of the proposed scheme to procure flexibility services is £2.710m.

Table 6.2: Summary of reinforcement costs and capacity volumes

Licence area	Voltage Level	No of sites	Total Capacity Required (MW)	Cost(£m)
SPD	EHV	5	32.50	0.395
	HV	11	40.79	0.681
SPM	EHV	3	51.27	0.767
	HV	27	48.38	0.868
			Total cost(£m)	**2.710**

Table 6.3: Cost incidence over the RIIO-ED2 period, £m (2020/21 Prices)

Total Investment	Total (£m)	Cost Incidence (£m)				
		2023/24	2024/25	2025/26	2026/27	2027/28
SPD	**1.076**	0.011	0.038	0.140	0.126	0.761
SPM	**1.634**	0.050	0.120	0.008	0.127	1.330
Total Expenditure (CV1-Primary Reinforcement)	**2.710**	0.061	0.158	0.147	0.253	2.091

6.4 Risks

The risks associated with adopted option are primarily due to the under-procurement of flexibility services to the required capacity, which has been discussed in section 5.1.2 under the proposed option.

6.5 Outputs Included in RIIO-ED1 Plans

There are no outputs expected to be delivered in RIIO-ED1 that are funded within this proposal.

6.6 Future Pathways – Net Zero

6.6.1 Primary Economic Driver

The driver for the proposed reinforcement is to defer the reinforcement in the manage the low risk constraint and high utilisation network areas and mitigate the constraints through procuring flexibility services.

6.6.2 Payback Periods

The CBA indicates that a positive NPV result in all assessment periods (10, 20, 30 & 45 years) which are consistent with the lifetime of the intervention. As indicated in the cost benefit analysis, the proposed solution defers the needs for network reinforcement beyond RIIO-ED2, hence the consumers benefit from reduced costs of supply.

6.6.3 Sensitivity to Future Pathways

The network capacity and capability that result from the proposed option is consistent with the network requirements determined in line with the section 9 of the Electricity Act and Condition 21. Additionally, the proposed option is consistent with the SPEN's Distribution System Operator (DSO) Strategy and Distribution Future Energy Scenarios.

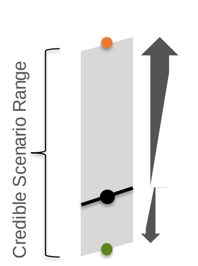
For both SPD and SPM areas, Table 6.4 shows electric vehicle and heat pump uptakes across a range of future pathways. Table 6-5 shows the sensitivity and scale of investment of the proposed solution for the proposed solution.

Table 6.4: Electric Vehicle and Heat Pump uptake volumes across a range of future pathways

End of RIIO-ED2		SPEN	DFES			CCC					
		Baseline	System Transformation*	Consumer Transformation	Leading the Way	Balanced Net Zero	Headwinds	Widespread Engagement	Widespread Innovation	Tailwinds
SPD	EVs	372k	166k	467k	546k	498k	343k	542k	493k	493k
SPD	HPs	205k	145k	332k	496k	199k	183k	222k	192k	200k
SPM	EVs	302k	158k	425k	480k	437k	302k	475k	433k	433k
SPM	HPs	161k	107k	215k	247k	182k	158k	195k	177k	173k

**Note: We have excluded System Transformation from our future pathways assessment as it does not meet interim greenhouse gas emission reduction targets.*

Table 6-5: Scale of investment



End of ED2 (2028)	Solution	SPD Cost (£m) / Groups (#)	SPM Cost (£m) / Groups (#)	Total Cost (£m) / Groups (#)
High	Conventional & Flexibility	9.615 / 16	12.384 / 30	21.998/ 46
Baseline	Flexibility	1.076 / 16	1.634 / 30	2.710 / 46
Low	Flexibility	1.076 / 16	1.634 / 30	2.710 / 46

The adopted solution is assumed to be robust across a wide range of pathways. The flexible capacity requirements will be directly dependent on the LCT uptake volumes and future demand connections in the network groups. The flexibility capacities will be assessed regularly (annually/bi-annually), hence the actual flexible capacity requirements will be refined during assessments and the tenders will be called on reflected the updated capacity requirements.

Under the highest uptake scenarios, few of the high utilisation network groups in both SPD and SPM areas are expected to foresee the thermal constrains built up earlier due to the accelerated uptake and may warrant a conventional build solution. Table 6-6. shows these networks groups, the least cost build solution and the costs.

Table 6.7 shows the sensitivity of the proposed RIIO-ED2 expenditure against the full ranges of Net Zero complaint future pathways.

Table 6-6: Additional volumes and cost under high uptake scenarios.

Licence Area	Scheme Name	Voltage (kV)	Reinforcement Description	Costs (£m)
SPD	CASTLE	11	Replant with 2x32 MVA primary transformer and ca. 8.5km 11kV UGC.	3.757
	WAROUT ROAD	11	Replant with 2 x 24MVA primary transformers	1.114
	CALAIS	11	Establish an additional primary infeed at Calais (with 1 X 20MVA TX, 1 x CBs and 3.6km 33kV UGC)	1.461
	CASTLANDHILL & PITREAVIE	33	New primary for Castlandhill, 2x 20MVA Tx, 2x 2km OHL & 2x 0.2km UGC 33kV, 2 x 33kV CBs on the new Inverkeithing board & 11x 11kV CBs for new switchboard	2.207
SPM	CAERGWRLE T1	11	Additional 10MVA primary transformer and 3x 33kV and 1x11kV AIS switchgear replacement	1.250
	APPLETON T1 / HORNSBRIDGE T1 / LUGSDALE T2	11	Additional 10MVA primary infeed at Hornsbridge, land purchase and 11kV board extension (possible building extension)	2.500
	DALLAM GT1 / SANKEY BRIDGES GT1 / WARRINGTON GT3	33	Additional 60MVA grid infeed from FC ckt into Dallam, (possible 132kV tower change) and132kV UGC ca. 0.5km long.	3.500
	PRENTON GRID GT1 / ROCK FERRY GT1	33	Additional 60MVA grid infeed from AH ckt into Prenton, (possible 132kV tower change) and 132kV UGC ca. 0.15km long and 33kV board extension.	3.500
			Total Cost(£m)	**19.288**

Table 6.7: Sensitivity of the proposed RIIO-ED2 expenditure

	Baseline	Uncertain
RIIO-ED2 Expenditure(£m)	2.710	19.288
Comment	Proposed option	Build solutions under highest uptake scenarios

6.6.4 Asset Stranding Risks & Future Asset Utilisation

Electricity demand and generation loadings are forecast to increase under all scenarios. The stranding risk is therefore considered to be low.

6.6.5 Losses / Sensitivity to Carbon Prices

Losses have been considered in accordance with Licence Condition SLC49 and the SP Energy Networks Losses Strategy and Vision to "consider all reasonable measures which can be applied to reduce losses and adopt those measures which provide benefit for customers". Reasonable design efforts have been taken to minimise system losses without detriment to system security, performance, flexibility or economic viability of the scheme. This includes minimising conductor lengths/routes, the choice of appropriate conductor sizes, designing connections at appropriate voltage levels and avoiding higher impedance solutions or network configurations leading to higher losses. Solution selection was not found to be sensitive to the impact of the carbon cost of losses.

Losses have been considered as part of this design solution and it has not been necessary to carry out any losses justified upgrades.

6.6.6 Whole Systems Benefits

Whole system solutions have been considered as part of this proposal. No alternatives have been identified that could be provided through a whole systems solution. The completion of this scheme will maintain the integrity of the distribution network and its enduring ability to facilitate wider whole system benefits.

6.7 Environmental Considerations

Due to the nature of the proposed intervention, there will be no impact in relation to SPEN's Business Carbon Footprint (BCF).

6.7.1 Supply chain sustainability

Due to the nature of the proposed intervention, there will be no impact in relation to the sustainability of our supply chain.

6.7.2 Resource use and waste

Due to the nature of the proposed intervention, there will be no impact in relation to resource use and waste.

6.7.3 Biodiversity/ natural capital

Due to the nature of the proposed intervention, there will be no impact in relation to biodiversity and natural capital.

6.7.4 Preventing pollution

Due to the nature of the proposed intervention there will be no impact in relation to pollution.

6.7.5 Visual amenity

Due to the nature of the proposed intervention, there will be no impact in relation to visual amenity.

6.7.6 Climate change resilience

Due to the nature of the proposed intervention, no impacts are anticipated in relation to future changes in climate.

7 Conclusion

This engineering justification paper proposes an innovative solution of managing the prospective network constraints in the high utilisation network areas, thereby reducing / deferring the need for a conventional reinforcement beyond the RIIO-ED2 period.

Summary of project scope:

For the RIIO-ED2 period procure additional flexibility services,

- In SPD licence area – 11 HV and 5 EHV groups for a total of 75.10MW at cost of £1.076m.
- In SPM licence area – 27 HV and 3 EHV groups for a total of 99.64MW at a cost of £1.634m.

The total cost of the scheme is £2.710m (in 2020/21 prices) with 100% contribution to be included in the RIIO-ED2 load related expenditure.

Note: The above sites and capacity requirements additional to the SPENs previous round of flexibility tenders floated in May 2021 and therefore the requirements and costs are pertained only to the sites and capacities mentioned in this scheme.

8 Appendices

Appendix 1. SPD High Utilisation Sites – Risk Hours and Capacity Requirements

Scheme Name	Voltage (kV)	Yearly Risk Duration (Hours)					Yearly Flexible Capacity procured (MW)					Cost (£m)
		2023/24	2024/25	2025/26	2026/27	2027/28	2023/24	2024/25	2025/26	2026/27	2027/28	
CASTLE	11	-	-	4	35	111	-	-	0.658	1.420	2.888	0.200
WAROUT ROAD	11	1	2	3	10	14	0.747	1.168	1.610	1.289	1.900	0.027
COLDSTREAM	11	-	-	2	19	55	-	-	0.130	0.465	0.932	0.034
CALAIS	11	-	4	23	107	254	-	0.313	0.871	3.687	3.914	0.256
PORTOBELLO	11	-	-	-	5	105	-	-	-	1.852	8.792	0.085
KINGSLAND	11	-	-	-	4	74	-	-	-	0.289	1.437	0.059
IRVINE	11	2	2	2	3	7	0.292	0.309	0.178	0.313	0.967	0.005
ANSTRUTHER	11	-	-	-	-	9	-	-	-	-	0.154	0.001
BOWHILL	11	-	-	-	-	13	-	-	-	-	0.454	0.003
MAYBOLE	11	-	-	-	-	15	-	-	-	-	0.319	0.002
MITCHELL STREET	11	4	4	4	6	7	0.580	0.620	0.100	1.330	0.810	0.008
LOCKERBIE GROUP	33	41	140	414	-	-	2.109	3.078	4.194	-	-	0.169
CASTLANDHILL & PITREAVIE	33	-	-	3	17	71	-	-	0.338	1.254	2.018	0.096
KAIMES 33kV CKT UPRATING	33	-	-	-	2	36	-	-	-	0.586	2.794	0.073
PORTOBELLO GSP	33	-	-	-	3	35	-	-	-	2.392	5.512	0.047
BRAEHEAD PARK GSP[3]	33	204	204	204	204	204	1.644	1.644	1.644	1.644	1.644	0.010
											Total Cost (£m)	**1.076**

[3] For Braehead Park, the risk hours and the capacity requirements are for security of supply under for N-1-1 condition.

Appendix 2. SPM High Utilisation Sites – Risk Hours and Capacity Requirements

Scheme Name	Voltage (kV)	Yearly Risk Duration (Hours)					Yearly Flexible Capacity requirement (MW)					Cost (£m)
		2023/24	2024/25	2025/26	2026/27	2027/28	2023/24	2024/25	2025/26	2026/27	2027/28	
EDERN T1[4]	11	-	3	7	21	60	-	0.10	0.25	0.44	1.02	0.089
MERE T1	11	-	-	-	7	915	-	-	-	0.85	2.26	0.075
LYMM T1 / WHITELEGGS LANE T1[5]	11	-	-	38	185	575	-	-	0.61	0.30	0.30	0.132
JOHNSTOWN T1	11	-	-	-	3	11	-	-	-	0.29	0.36	0.002
NANTWICH T1	11	-	-	-	7	52	-	-	-	0.50	0.89	0.024
RADWAY GREEN T1	11	-	-	-	-	19	-	-	-	-	0.56	0.005
RAVEN SQUARE T1	11	-	-	-	-	8	-	-	-	-	0.63	0.003
CAERGWRLE T1	11	-	-	3	45	269	-	-	0.16	1.78	2.65	0.092
APPLETON T1 / HORNSBRIDGE T1 / LUGSDALE T2	11	-	-	-	28	166	-	-	-	2.70	3.95	0.122
GWERSYLLT T1	11	-	-	2	11	77	-	-	0.53	0.95	2.85	0.068
TARVIN T1	11	-	-	1	9	71	-	-	0.07	0.48	1.53	0.061
ABERGELE T1 / PENSARN T1	11	-	-	-	8	70	-	-	-	1.37	3.64	0.069
COEDPOETH T1 / COEDPOETH T2	11	-	-	-	-	60	-	-	-	-	1.03	0.034
ANDERTON T1	11	-	-	-	4	35	-	-	-	0.33	0.54	0.009
HARTFORD T1	11	-	-	3	12	30	-	-	0.78	1.56	0.92	0.022
MACHYNLLETH T1	11	-	-			22	-	-	-	-	0.64	0.008
ABERSOCH T1	11	-	-	3	9	20	-	-	0.20	-	1.20	0.015
LLANIDLOES T1 / LLANIDLOES T2	11	-	-	-	1	13	-	-	-	0.25	1.24	0.009
FORDEN T1	11	-	-		3	13	-	-	-	0.13	0.20	0.001
LLANDRINIO T1	11	-	-	1	4	11	-	-	0.14	0.29	0.29	0.002
FRODSHAM LOCAL T1	11	-	-	-	-	10	-	-	-	-	0.42	0.002
SMALLWOOD T1	11	-	-	1	3	8	-	-	1.09	1.54	1.22	0.007
CEMMAES RD T1	11	-	-	-	-	5	-	-	-	-	0.31	0.001
HOLMES CHAPEL T1	11	-	-	-	-	3	-	-	-	-	0.29	0.000
BOW ST T1	11	-	-	-	-	2	-	-	-	-	1.10	0.001
NANT-Y-GAMAR T1	11	-	-	-	-	2	-	-	-	-	0.10	0.000

[4] For Edern primary substation, of the £71k expenditure, £50k is for RTTR installation on the primary transformer, the rest £39k is for flexible services.

[5] For Lymm – Whiteleggs Lane 11kV group, of the £132k expenditure. £120 is for 2xRTTR installations and automation, the rest £12k is for flexible services.

LLANILAR T1	11	-	-	2	13	57	-	-	-	0.19	0.38	0.014
AINTREE GT1 - FORMBY GT1- LITHERLAND GT2	33	-	-	-	-	25	-	-	-	-	1.77	0.021
DALLAM GT1 / SANKEY BRIDGES GT1 / WARRINGTON GT3	33	-	-	-	44	121	-	-	-	6.69	19.41	0.402
PRENTON GRID GT1 / ROCK FERRY GT1	33	-	-	11	42	104	-	-	2.85	5.26	15.29	0.344
											Total Cost (£m)	**1.634**

Appendix 3. Flexibility Service Products[6]

<table>
<tr><th>Category</th><th>Product</th><th>When required?</th><th>Metering Resolution</th><th>Type of remuneration</th><th>Earliest utilisation instruction notification</th><th>Latest utilisation instruction notification</th><th>Typical utilisation period</th><th>Frequency of use</th></tr>
<tr><td>A</td><td>Sustain</td><td>Scheduled forecast overload</td><td>HH metering</td><td rowspan="5">Utilisation and Availability</td><td>Scheduled in advance Years ahead</td><td>3 months ahead</td><td>Not defined, typically 3 to 24 hours</td><td>High: 5 deployments per week</td></tr>
<tr><td>A</td><td>Secure Scheduled</td><td rowspan="3">Pre-fault and peak shaving</td><td rowspan="5">metering requirements vary across DNOs</td><td>Contract stage</td><td>3 months ahead</td><td rowspan="3">not defined, typically 3 hours or more</td><td rowspan="3">Medium: 2 deployments per week</td></tr>
<tr><td>B</td><td>Secure Dispatched (week-ahead)</td><td>10 days ahead</td><td>3 days ahead</td></tr>
<tr><td>C</td><td>Secure Dispatched (real-time)</td><td>30 minutes</td><td>Real Time</td></tr>
<tr><td>D</td><td>Dynamic</td><td>Network abnormality or planned outage</td><td>15 minutes</td><td>Real time</td><td>Not defined, Typically several hours (it could take up to days)</td><td>Rarely, in case of faults</td></tr>
<tr><td>D</td><td>Restore</td><td>Network abnormality</td><td>Utilisation (it can also be availability only, it depends on DNOs)</td><td>15 minutes</td><td>Real Time</td><td>Not defined, Several hours to days, minimum 3 hours</td><td>Rarely, in case of complete loss of supply</td></tr>
</table>

6 https://www.energynetworks.org/assets/images/ON20-WS1A-P7%20Baselining%20Assessment-PUBLISHED.23.12.20.pdf