SSEN DISTRIBUTION RIIO-ED2

LOAD-RELATED PLAN BUILD AND STRATEGY

RIIO- ED2 Business Plan Annex 12

Scottish & Southern Electricity Networks

CONTENTS

EXECUTIVE SUMMARY

During the next decade our electricity network will undergo its most significant structural change since the formation of the National Grid.

The UK and Scottish Governments have set ambitious targets of net-zero by 2050 and 2045 respectively, requiring a total transformation of the way we use electricity in our everyday lives. Our electricity distribution network is integral to enabling our local communities' and wider governmental ambitions, by facilitating the decarbonisation of heat and transport, and enabling the connection of low carbon renewable generation.

In the ED2 period we are proposing to spend £393m on proactive load-related expenditure across our two networks; £322m in the South and £71 m in the North. This is in addition to the £149m related to customer connections. This will accommodate increases in demand we have identified as highly likely and will help ensure we do not foreclose future pathways. This expenditure will release an additional 2,500MVA of additional network capacity across our networks, 2,100MVA in the South and 400MVA in the North. Our expenditure also includes the procurement of flexibility services which enable us to better use existing capacity as an alternative to conventional constructed solutions.

We have followed a well-defined and robust process to develop our load-related investment plan, consistent with the approach outlined by Ofgem for use across all network companies. We have selected the DFES Consumer Transformation as the scenario underpinning our baseline plan. This is consistent with the feedback received through our stakeholder testing to assess local ambitions and needs. We have studied network conditions across all scenarios in ED2 to identify when and where network capacity constraints will occur. In each case we have considered a range of options to manage the anticipated constraint and ensure compliance with industry security planning standard P2/7 and related regulations.

In developing and proposing solutions we will meet the needs of our customers – both today and the future, including appropriate consideration of asset health and network reliability. In developing our expenditure plan we have used cost-benefit analysis (CBA) to select the most economic and efficient options for managing network constraints. This refinement process has enabled a cost reduction of around 36%, relative to our initial 'first-pass' bottom-up expenditure plan. We have 'stress-tested' our proposals with comprehensive sensitivity testing. This includes testing the impact of variation in peak demand and changes to the assumed cost of flexibility. From this analysis we have concluded that our proposed expenditure is robust, economic, and efficient for consumers.

We know that assumptions can change quickly, as a result of policy updates, market conditions and technological advances. Our scenario analysis estimates further expenditure of up approximately £211m could be required in ED2 across our networks. Having an agile and adaptive regulatory framework which is versatile to external changes is, therefore, vital.

We have been working directly with Ofgem and other stakeholders over the course of the last 18 months to consider the need-case and principles of operation for new forms of uncertainty mechanism, applicable to all DNOs. We propose Ofgem should pursue an automatic (volume driver) uncertainty mechanism for load related expenditure. The detailed design of a volume driver is currently being developed through cross-industry cooperation and we aim to be able to propose a detailed mechanism in our final ED2 business plan, pending successful completion of working group outcomes and indication of Ofgem support by early Autumn 2021.

1. INTRODUCTION

One of the critical functions of an electricity network is the ability to evolve to meet changing customer and consumer requirements; these usually manifest as network constraints due to changes to the supply and demand connected to our networks.

We refer to this as load-related expenditure. SSEN is well experienced in managing these changes and considering the resultant solutions for our 3.8m customers. SSEN has worked to find innovative ways to manage these constraints. In ED1 we have released approximately 657MVA of network capacity – equivalent to the capacity needed to power over 300,000 homes.

As we transition from ED1 to ED2 our sector will go through a pivotal change. The UK Government target to reduce carbon emissions to net-zero by 2050 is now in law; and in Scotland this target is the earlier date of 2045. These legally binding targets are reinforced by interim targets such as the ban on sales of new petrol and diesel cars by 2030 in England and 2032 in Scotland. Across our two networks 87% of local authorities have declared Climate Emergencies, with some setting net zero ambitions between 2025 and 2030. Our stakeholders are increasingly demanding rapid change, and we need to play our part.

We firmly believe that DNOs have a central role to play in the delivery of net zero, and that this must be reflected in the ED2 framework. However, the change is already underway. In just 10 months between January and October 2020 the UK witnessed a 129% increase in passenger EV sales, and a 35% decline in sales of internal combustion engine vehicles[1]. The 6th Carbon Budget announced in December 2020 signifies the importance of the next 15 years whereby 60% of the emissions reduction needs to be realized if we are to meet our targets as a country.

DNO load-related expenditure is integral to decarbonisation of heat and transport, and to the connection of low carbon renewable generation. Our DFES scenario range suggests national peak demand could increase by 6.8GW (Consumer Transformation) in ED2; with approximately 558,000 EV charge points approximately 512,000 heat pumps, and with 2,600MW of distributed generation connecting across our networks. In order to successfully deliver this and the longer-term net zero legislative targets we must actively balance the interests of current and future consumers, recognizing that investment today will help keep bills low in the future, delivering wider societal benefits and resulting in lower costs to consumers overall. DNOs must be able to facilitate growth in a timely and efficient manner whilst also minimizing disruption.

In this Annex we summarize our proposals and describe our approach to load-related expenditure decision-making. We highlight the key insights pertinent to understanding our proposal rationale and explain why we have set our proposals over alternatives; including what needs to be believed for our proposals to change. We explain the actions we will take to deliver these proposals and how we have concluded these are the most economic and efficient choices co-created with stakeholder expectations.

[1] Bloomberg New Energy Finance Executive Factbook 2021.

Finally, we know the future world we operate in could be different to the one on which we build our plan, so we also discuss where, and why, this could be the case and what we propose to do about it; including how we can retain optionality and ensure long-term consumer value.

2. SETTING THIS ANNEX INTO THE CONTEXT OF OUR PLAN

In this annex we articulate the detail of our load-related investment proposals for our two licence area networks, SHEPD (North) and SEPD (South). These proposals complement the higher-level summary of our strategy in ***Responding to the net zero challenge (Chapter 10)*** of our business plan submission, within the Business Plan Section: Smart, Flexible & Net Zero Energy System.

Load-related expenditure is required to resolve capacity restraints on our network. Our primary driver for load related expenditure is changing customer requirements, such as the volume and location of generation and demand connected to our network. In Section 5.2[2] of this annex, and in ***Forecasting and Scenarios (Chapter 9)*** of our Business Plan, we provide more substantive detail on these drivers. Load related expenditure also includes replacement of equipment in cases where the fault level capability is no longer adequate, as a result of changes in demand and generation, or when we need to upgrade the capacity of our connections to the transmission network.

This annex should be read in conjunction with tables CV1-CV4 in the Business Plan Data Tables (BPDT) which provide costs and volumes on load related expenditure[3]. Connections-related reinforcement expenditure is set out in BPDT C2.

Our load related expenditure plan relates to, and has interdependences with, the following Business Plan Annexes which are cross-referenced with this annex.

- ***DSO Strategy (Annex 14)***
- ***Connections Strategy (Annex 13)***
- ***Whole Systems (Annex 15)***
- ***Innovation Strategy (Annex 18)***
- ***Cost Efficiency (Annex 19)***
- ***Benchmarking (Annex 20)***
- ***Uncertainty Mechanisms (Annex 28)***

The overarching strategy for low voltage (LV) network is also provided in Appendix D to this Annex.

Additionally, this Annex is supported by detailed Engineering Justification Papers (EJPs) and Cost Benefit Analysis (CBA) documents which are included in our submission. These provide detailed justification for individual investments which make up the costs and volumes in our plan.

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2 Also in Appendix E to this Annex.

3 tab 'LI Substations' which related to primary network utilization; and to table M20 for supplementary information.

Unless otherwise stated, the numbers presented in this Annex are for both of our licence network areas (SSEN total). The EJPs and CBAs we provide a detailed breakdown for each of our licence areas for key tables and charts.

Side bar 1: Load related expenditure reporting classification

There are four types of load related investment expenditure which DNOs are required to report on to Ofgem through the Business Plan Data Tables:

1. Primary network reinforcements
2. Secondary network reinforcements
3. Fault level reinforcements
4. New transmission capacity charges

Primary network reinforcements – are activities undertaken to resolve capacity constraints on the on the Primary Network (33kV and above). Aka. Extra High Voltage (EHV). DNOs must disaggregate between investments on circuits which require n-1 and n-2 levels of redundancy. Further DNOs must disaggregate between conventional substation and circuit solutions; innovative solutions; and flexibility services solutions. In all cases DNOs must report costs and capacity (MVA) released.

Secondary network reinforcements – are activities undertaken to resolve capacity constraints on the Secondary Network (Low Voltage (LV) and High Voltage (HV)). DNOs must disaggregated between reinforcement done at pole mounted and ground mounted substations; and between conventional; innovative and flexibility services solutions. In all cases DNOs must report costs and capacity (MVA) released.

Fault level reinforcements – are activities undertaken to replace equipment when the rated fault level they can withstand is no longer adequate. DNOs must report the number of fault level constraints resolved by asset class (switchboard, circuit or other). Further DNOs must disaggregate by voltage level and type of solution: conventional or innovative.

New Transmission Capacity Charges – are activities initiated by DNOs for increased capacity at existing transmission connection points or for new transmission connection points. DNOs must capture expenditure information relating to the charges payable by the DNO to a transmission licensee for projects which have been initiated by the DNO but carried out by the transmission licensee. Reporting must disaggregate between reinforcement of existing transmission connection points and new transmission connection points.

Load Related Expenditure does not include costs associated with High Value Projects.

3. WHAT CONSUMERS WILL GET FROM OUR PROPOSALS?

Our overarching strategy for ED2 is firmly centred on our core purpose 'We power our communities to thrive today and create a Net-zero tomorrow'. We are focused on creating a strong foundation to meet new demands and making a net-zero world a reality for our customers and communities. Our plan is co-created with our stakeholders and customers, to deliver a local and inclusive transition to net-zero. Across our plan we will do this by providing:

- A safe, resilient and responsive network;
- A valued and trusted service for our customers and communities;
- An accelerated progress towards a net zero world; and
- A positive impact on society

On load-related expenditure our aim is to ensure that enough network capacity is available to actively support our local communities in contributing to the achievement of net-zero. We want to ensure that we are never a barrier, nor perceived to be a barrier, for the timely connection and efficient use of LCT, such as electric vehicles (EV) and heat pumps. Furthermore, it's of the utmost importance that the level of service and reliability received by our existing customers is not compromised or adversely impacted by the uptake in LCT. Table 1 provides details of our key load-related outputs.

Table 1- Regulatory outputs summary

Output	Output type	RIIO-ED2 target	Costs	Stakeholder evidence and consumer benefits
Enabling the connection of Low Carbon Technology (LCT)	SSEN goal	Enable the timely connection of approximately 1.3m EVs and 800,000 heat pumps	£393m	Our business plan combines takes a "flexibility first" approach to facilitating net zero, and our investment proposals reflect our local communities' ambitions.

In ED2 we propose a total ex-ante baseline allowance of £393m in the ED2 period on proactive load related investments across our two networks. This covers expenditure which we identify as being highly certain and expenditure proposed so that future pathways are not foreclosed. Section 5 of this annex provides an explanation of our rationale for this proposal and a breakdown. This equates to approximately 10% of our total baseline allowance request across our plan. In Table 2 we summarize the load-related ex-ante baseline proposal across the ED2 period by expenditure type aligned with Ofgem's reporting classification[4].

[4] A detailed breakdown of this allowance is provided in Appendix F.

Table 2: summary of SSEN's load-related investment in the ED2 period by reporting category

Type	CV table	2023-24	2024-25	2025-26	2026-27	2027-28	Total (£m)
Primary	CV1	£37.7	£40.7	£44.4	£34.6	£48.9	£206.6
Secondary	CV2	£21.5	£24.3	£25.7	£24.4	£14.2	£110.5
Fault Level	CV3	£13.2	£4.9	£30.7	£4.1	£3.6	£56.6
NTCC	CV4	£2.6	£3.9	£4.2	£4.3	£4.3	£19.4
TOTAL		£75.0	£73.8	£105.0	£67.4	£71.0	£393.1

Table 2 shows ex-ante baseline expenditure. It should be noted that we anticipate the potential for further expenditure in the ED2 period of around £211m linked to stronger growth in demand from EVs or heat-pumps as a result, for example, of further Government policy decisions, technological developments or market forces. This additional amount is not included in Table 2 or our proposed ex-ante baseline allowance. A further discussion on how we have derived this baseline funding proposal can be found in section 5 of this document. In section 7 we discuss our approach to funding the additional allowances through uncertainty mechanisms.

3.1 PRIMARY AND SECONDARY REINFORCEMENTS

Our ex-ante baseline expenditure on primary and secondary reinforcements will enable 2,674 MVA of capacity to be released on our networks. This will be achieved through a combination of conventional (constructed) asset solutions, innovative solutions and flexibility services. We expect 10% of this additional capacity to be provided through the procurement of flexibility services rather than conventional network-based solutions. This 'capacity released' will be enough to enable the connection to our network of over a million EVs and heat-pumps in the ED2 period. This will be key in enabling the achievement of our strategic ambition to facilitate the connection of 1.3m EVs and 800,000 heat-pumps by the end of ED2. Table 3 summarizes the total capacity released on our primary and secondary networks; and Table 4 summarizes the total number of LCT, by type, which are enabled by our baseline proposal, along with the associated connected LCT MW across all voltage levels for both our networks[5]. Figure 1 shows the anticipated growth in the number of heat pumps, electric vehicles and photovoltaic installations in our licence areas over the ED2 period.

Table 3: summary of SSEN's capacity release in the ED2 period by reporting category (MVA)

Type	CV table	2023-24	2024-25	2025-26	2026-27	2027-28	Total (MVA)
Primary	CV1	237.0	431.8	308.0	226.6	26.0	1229.4
Secondary	CV2	164.2	196.1	209.6	212.6	129.1	911.5

[5] Data in table 3 is summarised from table M20 in the business plan data tables.

Table 4: summary of SSEN's LCT volumes and MW enabled in the ED2 period- Consumer Transformation (per year).

LCT type		2023-24	2024-25	2025-26	2026-27	2027-28	Total
Heat Pumps	#	73763	81073	95847	129955	131793	512,430
	MW	332	365	431	585	593	2,306
EV charge points (slow)	#	59210	75726	139211	139096	139176	552,419
	MW	414	530	974	974	974	3,867
EV charge points (fast)	#	688	838	1039	1285	1486	5,336
	MW	54	62	76	96	109	397
PVs	#	12464	13308	17372	21378	21566	86,088
	MW	47	51	66	81	82	327
Other DG (G98)	#	180	225	269	3663	3246	7,583
	MW	1	1	1	13	11	27
DG (non-G98)	#	540	634	536	318	271	2,299
	MW	540	635	535	318	271	2,299

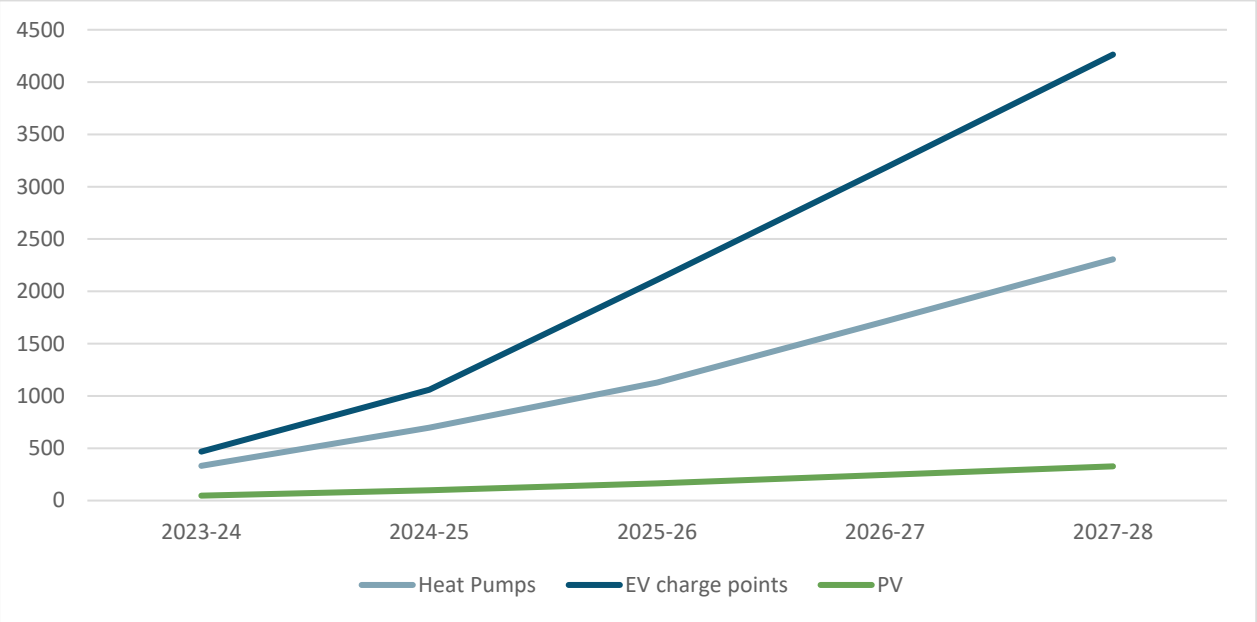

Figure 1 - Growth in LCT units in SSEN area in the ED2 period (Consumer Transformation).

As well as releasing capacity and enabling the connection of LCT, our investments will also provide further benefits to consumers. These include a positive impact on long-term network reliability associated with the number and duration of supply interruptions. This is a key consumer benefit metric which justifies our reinforcement decision in Cost Benefit Analysis (CBA), in addition to compliance with mandatory network planning security standards.

We understand the importance of demonstrating that our investment decisions are efficient throughout the ED2 price control period. In Figure 2 we summarize the number of primary demand groups in each of

the load index ranking groups LI1-LI5, before and after intervention[6]. Figure 3 summarises the number of ground-mounted substation and pole-mounted substation sites falling within a set of utilization bands, before and after intervention[7].

As a result of the increased demand we will, in the first instance, make greater use of our existing assets by procuring flexibility services. This will increase capacity utilisation and ensure that a greater percentage of our assets will be more fully utilised on the network, as shown in both Figure 2 and Figure 3. The shifting of the curve in the middle plots to the right from the 2021 position illustrates this. However, without network intervention the instances of overload, which can be a risk to network reliability, will increase. The right-hand plot in Figure 2 and Figure 3 shows the intervention benefits by reducing the occurrence of extreme asset overloading. Furthermore, these 'with intervention' plots are associated with our ex-ante baseline proposal. It is anticipated that the residual asset overload shown would be addressed and funded through uncertainty mechanism.

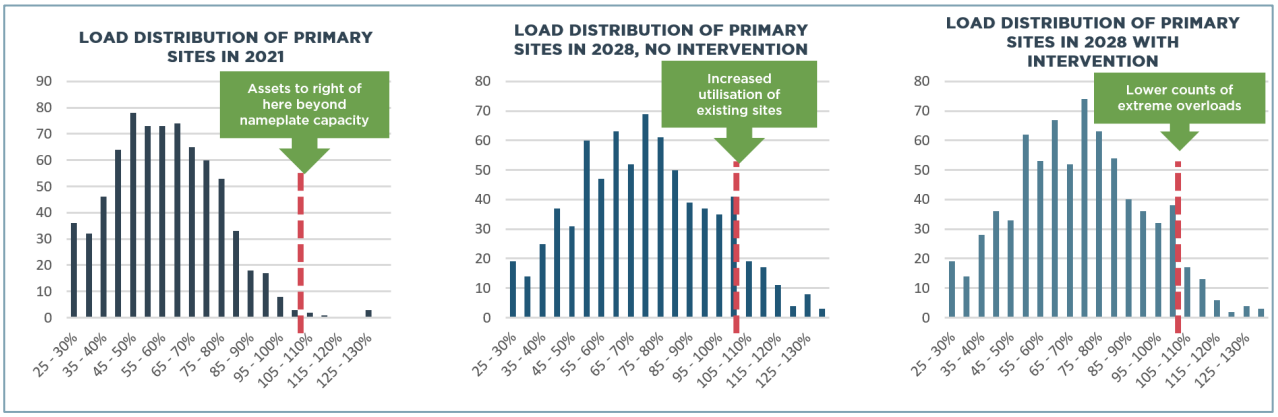

Figure 2: Number of primary demand groups in each of the load index ranking groups before & after intervention.

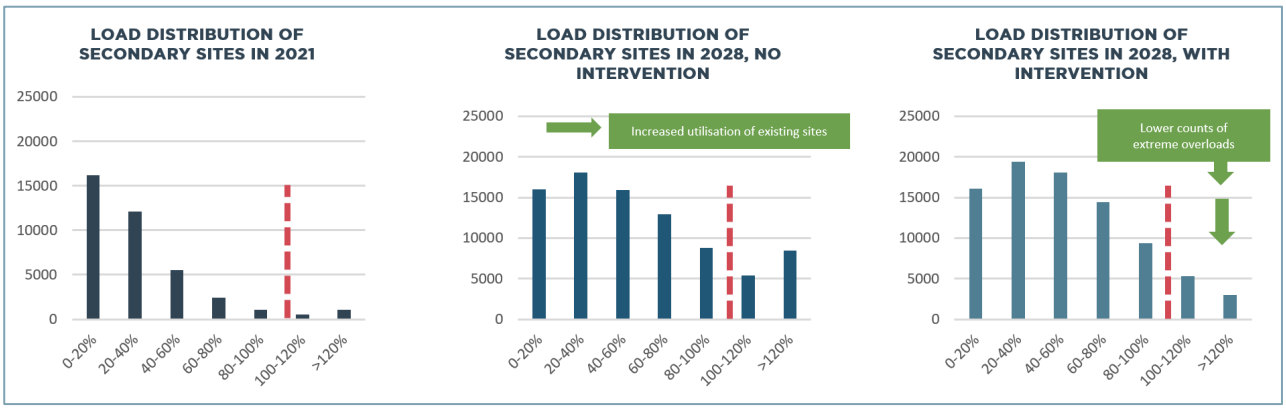

Figure 3- Utilization of secondary assets with and without intervention

6 Data in Figure 2 is summarised from analysis conducted using the Consumer Transformation baseline scenario.

7 Data in Figure 3 is summarised from table CV2 memo tables using the Consumer Transformation baseline scenario.

Side bar 2: Network utilisation assessment

Network utilisation is one measure of the efficacy of our reinforcement expenditure decisions over the price control period.

At the primary network level, an established regulatory reporting measure is in place called the Load Index (LI). The LI categorises primary substations into five bands (LI1 to LI5) based on the percentage loading, or utilisation, of each substation. This loading percentage is the percentage of the substation firm capacity that is used at the time of maximum demand. At present, the LI metric is only applied to primary networks. This is mainly due to limitations associated with secondary substation monitoring. Although subject to regular reporting, there is currently no formal regulatory output associated with network utilisation. One of the challenges is that there are multiple factors that can contribute to level of network utilisation.

For the ED2 period Ofgem has indicated its intention to continue with LI reporting. In addition, Ofgem has asked DNOs to report *modelled*, as opposed to *measured*, network utilisation at the secondary network level – for both pole-mounted and ground-mounted substations. Modelled data is used in recognition of the limitation in the coverage of monitoring data at the lower voltage levels. SSEN proposes to increase measuring and monitoring coverage in ED2 (see section 6 for further details).

Discussions are ongoing between Ofgem, DNOs and industry stakeholders with regard to applying specific regulatory outputs for load indices and their interaction with allowances set through uncertainty mechanisms.

3.2 FAULT LEVEL REINFORCEMENTS & NEW TRANSMISSION CAPACITY CHARGES (NTCC)

Our ex-ante baseline allowance proposal for fault level reinforcement work will enable 262 fault level constraints to be resolved in the ED2 period. The number of fault level constraints resolved, disaggregated by asset type, is shown in Table *5*[8]. Further disaggregation by solution type is provided in Section 4 of this document.

Table 5: Number of fault level constraints resolved by asset type

Asset type	2023-24	2024-25	2025-26	2026-27	2027-28	Total (#)
Switchboard	121	0	49	0	0	169
Circuit	19	21	16	17	20	93

Consumers will benefit from these interventions on the network, which result in no assets operating at more than 95% of their duty rating or with fault level operational restrictions.

[8] Data in table is summarised from table CV3 in the business plan data tables.

In Table 6 we outline a proposal to spend £19.4m across ED2 on New Transmission Capacity Charges. This is payment is to transmission licensees for projects which have been initiated by us but carried out by the transmission licensee. In Table 6[9] we outline which of these are for reinforcement of existing connections and which of these are associated with new connections.

In Section 4 of this annex we provide further detail on the actions which will be taken to deliver on these proposals.

Table 6- NTCC impact of our plan

Asset type	2023-24	2024-25	2025-26	2026-27	2027-28	Total (£m)
Reinforced	2.6	3.9	4.2	4.3	4.4	19.4
New	-	-	-	-	-	-

3.3 FLEXIBILITY DEPLOYMENT

Flexibility services play a critical role facilitating the connection of Low Carbon Technologies (LCT) to networks as well as bringing value to the wider energy system through wholesale markets and in the provision of national system services for the Electricity System Operator (ESO).

The key benefit from the use of flexibility services in our business plan is in enabling the rapid uptake of LCT in a way that is efficient, effective and delivers value to customers in the long-term. Procuring flexibility services enables smart management of network capacity. It allows us to delay decisions to invest in conventional constructed solutions. This provides both deferred capital expenditure benefit, as well as realising the value of 'waiting' for more certainty of the need for network capacity in an otherwise uncertain future, thereby reducing the risk of long-life stranded assets.

Flexibility also enables us to increase the efficiency of the existing network through increased levels of utilisation, and to deliver enhanced Customer-Minutes Lost (CML) performance derived from flexibility-based restoration options. The use of flexibility enables us to directly reduce business operational costs and lower carbon emissions associated with the use of mobile and static diesel generation, and also delivers broader societal and community benefits associated with not constructing capital works (e.g. traffic disruption).

In addition, we expect the demand for major flexible connections to grow in ED2, and under our baseline scenario (CT) we expect to offer more than 200 new connections in the ED2 period, totalling 2GW. This will take our overall total of flexibly connected generation capacity to around 3.6GW by the end of the ED2.

We have prepared our ED2 plan to deal with the full range of high and low uptake scenarios and the associated variation in network impact. We have prepared well-justified plans for conventional network investment where peak demand growth uncertainty is low and the customer cost of failure to meet LCT demand is high. At the same time, we are fully equipping ourselves with the capability to make effective

[9] Data in table is summarised from table CV4 in the business plan data tables.

use of flexibility services to enable us to deal efficiently with unexpected outcomes through full and supportive engagement in the developing marketplace.

Table 7 summarises the scale of flexibility deployment and the potential savings quantified from advancing these flexibility schemes[10]. This represents an estimated view of using flexibility services for EHV, HV and LV schemes.

Table 7- Impact of flexibility on our Load plan

Summary- application of flexibility in Load	
CAPEX deferred to ED3	£22.3m - £49.8m
CAPEX savings in ED2[11]	£5.0m - £8.5m
Cost of procuring flexibility services	£9.3m - £8.1m
Flex Capacity considered	810MVA
Flex Capacity used	272 - 368MVA

Side bar 3: Load Managed Areas (LMA)

LMA are a legacy system used to manage network capacity in the SHEPD licence area. LMAs reduce the maximum demand on circuits and at substations by controlling customer space heating and water heating load at different times during day and night via Long Wave Radio Tele-Switching (RTS). LMAs cover approximately 93,000 customers in rural areas. They were historically introduced as an alternative to traditional reinforcement in rural parts of the network where costs are prohibitively expensive.

Our approach in ED2 will be to use market flexibility services to replace LMA mandated switching patterns – including activities to define, develop and stimulate the market – alongside, and in accordance with, development and facilitation of flexibility markets to support DSO.

Solutions to provide additional capacity to support the uptake of LCT will be co-optimised with those to remove LMA restrictions – using the principle of 'flexibility first' We will also ensure that all/any other reinforcement or flexibility procurement for other (non-LCT) needs or requirements provides for LMA removal, as a matter of course.

More detail on our proposed approach to removal of LMA restrictions is provided in Appendix C of this Annex.

10 Not all benefit streams listed are quantified in this summary, due to the lack of industry wide agreement on quantifying the optionality benefit.

11 Direct savings, as defined in the ENA's Common Evaluation Methodology, come from the benefit of delaying investment, hence accessing the time value of money being deferred- less the cost of procuring the flexibility.

4. WHAT ACTIONS WILL BE TAKEN TO DELIVER ON THESE PROPOSALS?

In this section we provide a breakdown of the investments underpinning our ex-ante baseline allowance proposal set out in Section 3. This is supported by a summary of our rationale supporting these proposals. Further commentary is provided in section 5. Additionally, in sub-section 4.3 we summarise the business operational changes needed to realise the anticipated benefits.

4.1 PRIMARY AND SECONDARY NETWORK REINFORCEMENTS

The proposed ex-ante baseline funding associated with our primary network, as outlined in Table 2 will be delivered through a mixture of conventional, innovative and flexibility solutions across the 33kV primary network in the North and the 33kV and 132kV network in the South. Table 8 provides details of the total capacity released by different solution types for our North network, and Table 9 for the South network. A further breakdown is provided in Business Plan Data Table (BPDT) CV1[12].

Table 8: capacity released on our primary network (North) by reinforcement type in our ex-ante baseline plan (CV1 table)

Reinforcement type	2023-24	2024-25	2025-26	2026-27	2027-28	Total (MVA)
Conventional	54.2	6.6	29.8	38.6	0.0	129.2
Flexibility	0.0	1.5	1.0	0.0	0.1	2.6

Table 9: capacity released on our primary network (South) by reinforcement type in our ex-ante baseline plan CV1

Reinforcement type	2023-24	2024-25	2025-26	2026-27	2027-28	Total (MVA)
Conventional	178.0	411.2	263.8	187.7	25.9	1066.6
Flexibility	4.8	12.5	13.5	0.3	0.0	31.1

On the secondary network, the ex-ante baseline funding outlined in Table 2and associated capacity released outlined in Table 3 will be delivered through mixture of conventional and flexibility solutions.

The capacity released calculation at secondary level focusses on low voltage substations (11kV/LV) - both pole-mounted and ground-mounted. This follows a defined methodology that ensures no double-counting of capacity where multiple assets on a circuit enable the same capacity. There are a wide variety of solutions proposed in the plan which enable the capacity release shown in the tables.

[12] Disaggregation in business plan data tables is by primary and secondary voltage of substations; by single substations and substation groups; and by level of redundancy on the network (N-1 or N-2).

Table 10: capacity released on our secondary network (North) by reinforcement type in our ex-ante baseline plan

Reinforcement type	2023-24	2024-25	2025-26	2026-27	2027-28	Total (MVA)
Conventional	32.0	35.0	25.0	23.3	14.4	129.8
Flexibility	1.3	1.9	2.4	1.7	1.6	8.8

Table 11: capacity released on our secondary network (South) by reinforcement type in our ex-ante baseline plan

Reinforcement type	2023-24	2024-25	2025-26	2026-27	2027-28	Total (MVA)
Conventional	119.2	135.3	162.6	166.0	97.6	680.7
Flexibility	11.7	23.9	19.7	21.5	15.5	92.2

4.2 FAULT LEVEL REINFORCEMENTS & NEW TRANSMISSION CAPACITY CHARGES (NTCC)

Our proposed ex-ante baseline funding includes delivery of solutions for fault level issues on the network. These solutions will be delivered through a mix of conventional and innovative solutions. Typical conventional solutions employed by SSEN include a mixture: replacing the switchgear; increasing the size of cables; replacing transformers with higher impedance units and reconfiguring the network to split busbars. Some of the innovative solutions employed by SSEN include fault current limiting devices, and real-time management of fault level. The exact solution is heavily dependent on-site specific factors which are discussed in the EJPs. Figure 4 provides a breakdown by solution type is provided for our networks.

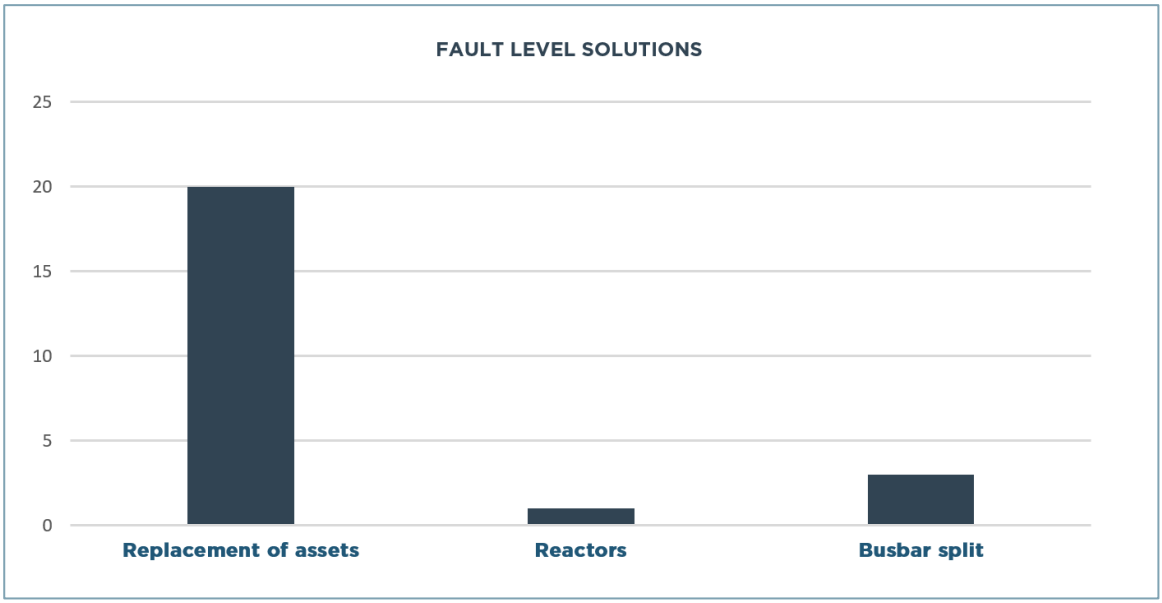

Figure 4: breakdown of solution type for fault level reinforcement works

4.3 WHAT DO WE NEED TO DO AS A BUSINESS TO DELIVER OUR LOAD RELATED PLAN?

Our deliverability strategy detailed in ***Ensuring Deliverability and a Resilient Workforce (Chapter 16)*** of the Business Plan describes our approach to evidencing the deliverability of our overall plan as a package, and its individual components. Testing of our EJPs has prioritised assessment of efficiency and capacity, and this has ensured that we can demonstrate a credible plan to move from SSEN's ED1 performance to our target ED2 efficiency. We have also demonstrated that our in-house and contractor options can, or will through investment or managed change, provide the capacity and skills at the right time, in the right locations. This assessment has been part of the regular assessment of our EJPs, CBAs and BPDTs, and we will further refine our bottom up efficiencies and work plan phasing for our final submission in December 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 SSEN will change the way Capital Expenditure is delivered, maximising synergies within the network to minimise disruptions for our customers. This is particularly relevant for a Price Control period where volumes of work are increasing across all work types.
- The principle is to develop and deliver Programmes of work, manage risk and complexity at Programme level and to develop strategic relationships with our Suppliers and Partners to enable efficiency realisation.
- 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.

5. WHY DID WE CHOOSE THESE INVESTMENT PROPOSALS OVER ALTERNATIVES?

In Sections 3 and 4 we set out what consumers will get from our proposed ex-ante baseline allowance and what actions we will take to deliver these investments, along with a summary of our rationale supporting these proposals. In this section we provide a more expansive commentary of the methodologies we have used to develop our ex-ante baseline proposals, and why we are confident these proposals are in consumers' interests. We set out the key trends influencing our choice of load-related investment and what needs to be believed for these proposals not to be correct. We also assess how our future expenditure plan might need to adjust if there are changes in the assumptions upon which our ex-ante baseline plan is built. In Section 7 we set out our proposals for managing a different future to the one on which our plan is built.

Detailed EJP and CBA have been prepared to support this section. These give specific and extensive evidence on individual or grouped investments.

The content of this chapter is core to the demonstration of compliance with the Ofgem business plan minimum requirements[13].

In this section we set out the overall process which has been used to populate the load-related expenditure business plan data tables.

5.1 END-TO-END APPROACH FOR DEVELOPING OUR LOAD PLAN

We have followed a robust four step process to develop our load-related expenditure plan, as summarised in Figure 5. The four core steps of this process are consistent with the Load Related Methodology Guidance issued by Ofgem in April 2020 and is therefore consistent with the approach used across DNOs. Table 12 provides a top-level explanation of the process steps and in sub-sections 5.2 to 5.5 we give a comprehensive explanation of the methodology and our critical insights, including how these flow into the summary information presented earlier in sections 3 and 4.

[13] Relevant minimum requirements as set out in Ofgem Business Plan Guidance Document, paragraph 5.1-1.5.25. Appendix A provides specific section detail on demonstration of our minimum requirement within the business plan.

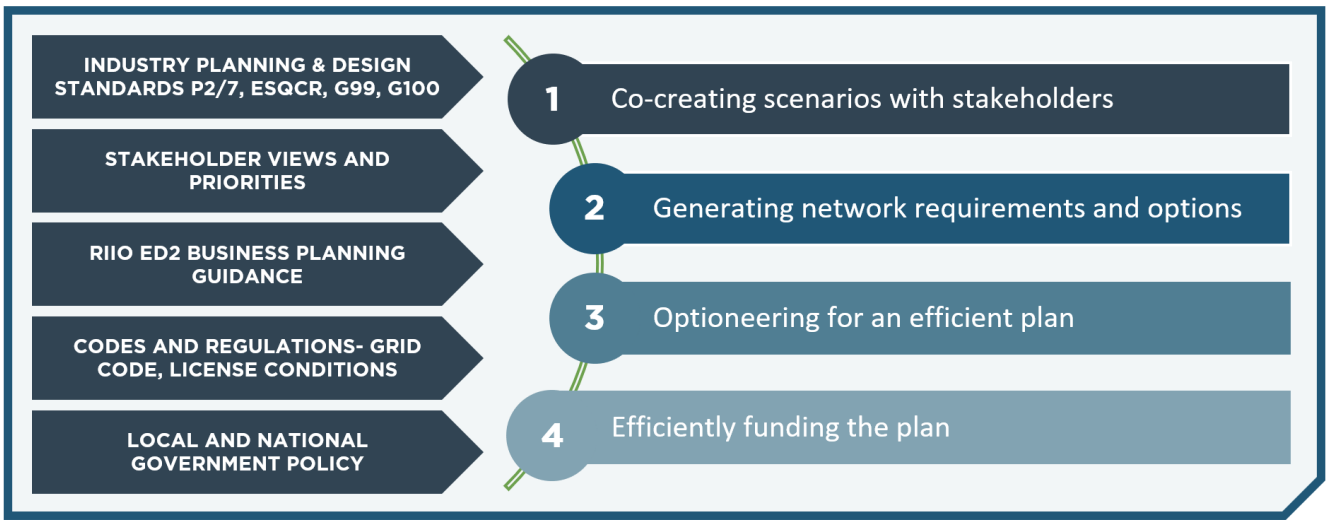

Figure 5- End-to-end process for generating ED2 load related expenditure

Table 12- Structure of this section (Section 5).

Section	Content
5.2	**Co-creating scenarios with stakeholders**: Firstly, a discussion of how we co-created our understanding of the future with stakeholders through our enhanced engagement process. This explains our choice of scenarios, particularly our baseline scenario, and how we have used the scenarios to quantify the demand that the network is likely to experience in ED2, to support the journey to a net-zero.
5.3	**Generating network requirements and options**: Showing how we have interpreted the scenarios in terms of network constraints and how we study these through power flow analysis to identify the need for network intervention. The range of options developed for addressing these intervention needs are requirements described.
5.4	**Optioneering for an efficient plan**: Assessing credible options and identifying the best option for consumers' interests is described, through the Cost Benefit Analysis process, and accompanying sensitivity analyses that increase confidence that our plan will deliver for consumers whichever pathway towards Net Zero is followed.
5.5	**Efficiently funding the plan**: Finally, a synthesis of how our ex-ante baseline plan, and the associated investments, come together. This is mapped to regulatory requirements and outputs; including expectations set out by Ofgem on categorization of expenditure.

Our approach to enhanced engagement

Stakeholders have had a far stronger voice in shaping our ED2 Business Plan than ever before. Our programme of inclusive, insightful, impactful and iterative enhanced engagement has enabled our stakeholders, customers and consumers to co-create the Business Plan with us. This transformed approach to stakeholder engagement is described in detail in our ***Enhanced engagement strategy (Annex 01***).

The Enhanced Engagement Appendix (see page 75) demonstrates the golden thread that connects stakeholder opinion to the outputs we will deliver during ED2. It begins with a synthesised list of the

actionable insights we gained about Local Network Plans, and how these have been implemented in the Business Plan. The sources of this evidence are scored for robustness, and the insights 'triangulated' against each other, which allowed output owners to trade off dissenting views and ensured that the most robust feedback had the greatest impact on the content of the Business Plan.

A summary of all of the stakeholder evidence that informed our load outputs, including how it was assessed and triangulated, can be referenced on pages 75-79

Evidence Summary

ED2 ENGAGEMENT EVENTS

15

SOURCES OF INSIGHT

155

NUMBER OF STAKEHOLDERS

1,587

Stakeholder segments engaged

The stakeholder segments engaged are highlighted in purple in Figure 6

CONSUMERS	Domestic customers	Customers in vulnerable situations	Transient customers	Next generation bill payers	SMEs	Major energy users	
CUSTOMERS	Distributed generation customers	Builders and developers	Community energy schemes	Landowners/ farmers			
POLICY MAKERS AND INFLUENCERS	Government	Research bodies, policy forums and think tanks	Media	Consumer groups	Regulators		
COMMUNITIES AND LOCAL DECISION MAKERS	Local authorities	Charities	Academic institutions	Housing associations			
	Vulnerable customer representatives	LEPs	Emergency response	Healthcare	Community interest bodies		
WIDER INDUSTRY AND VALUE CHAIN	DNOs	Transmission	GDNs	Water	Telecoms	IDNOs	
	ICPs	Consultants	Energy suppliers	EV charging	Other supply chain	Storage and renewable providers/ installers	Transport and highways agencies
PARTNERS AND ENABLERS	Current and future employees	Contractors	Service partners	Shareholders	Investors	Business advisers	Trade Unions

Figure 6 - Stakeholder segments engaged about load plans

5.2 CO-CREATING SCENARIOS WITH STAKEHOLDERS

Our baseline plan is ex-ante and is based on a set of assumed changes to generation and demand connected to our network driving. This defines our forward view on the expenditure needed to manage the resultant constraints on the network. In section 7 we discuss how our plan can adapt to changes in the ED2 period. Central to developing base-case expenditure is an understanding of the range of future pathways or scenarios which could credibly materialise, taking account of stakeholder views. This informs selection of an appropriate base-case view for the ex-ante plan.

Our future scenarios are based on the range of assumptions found in the net-zero compliant energy pathways in the Electricity System Operator's (ESO) 2020 Future Energy Scenarios (FES)[14], and the Committee on Climate Change (CCC) 6th Carbon Budget[15]. We have used these key assumptions as part of determining the range of demand for our network over the ED2 period and beyond. Using a scenario-based approach is not new for industry or SSEN; we have successfully applied it in ED1.

The scenarios produced by the ESO are set at the national level for all Great Britain. Whilst a top-level view of generation and demand by DNO licence area is provided it is necessary to create a more detailed bottom-up view which includes local intelligence and reflects relevant planning and development activities in our licence areas. For this purpose, we have produced a set of Distribution Future Energy Scenarios (DFES) using the same scenario framework as the ESO FES.

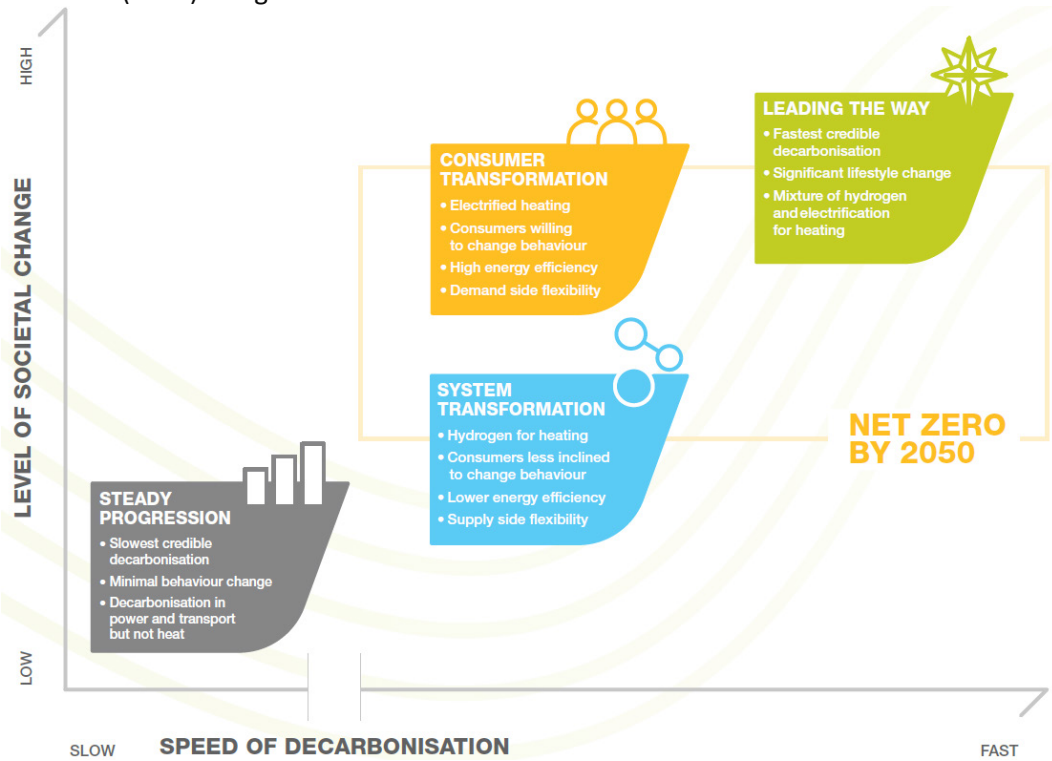

Figure 7 shows the scenario framework used for 2020 in the FES and DFES.

14 https://www.nationalgrideso.com/document/173821/download
15 https://www.theccc.org.uk/publication/sixth-carbon-budget/

Side bar 4: The four Future Energy Scenario (FES) trajectories

- **Steady Progression**: Slowest credible decarbonization of all the scenarios with minimal behavioural change of consumers. Decarbonisation of power and transport but not in heat by 2050. It doesn't achieve a net-zero by 2050 target
- **System Transformation**: Meets net-zero by 2050 but with consumers less inclined to change behaviour and lower uptakes of energy efficiency compared to the other net-zero complaint scenario. Supply side flexibility is prominent as is hydrogen for heating
- **Consumer Transformation**: Meets net-zero by 2050 but with shifts in consumer behaviour driving; including high uptakes of energy efficiency and demand side flexibility and electrified heating
- **Leading the Way**: The fastest credible decarbonization pathway. Centred on significant lifestyle changes for consumers; but a mixture of hydrogen and electrification for heating

A first critical step we have undertaken with our stakeholders is to create a bottom-up DFES framework from the ESO national FES framework. This is an annual process and is carried out separately for each of our licence areas with the support of consultancy Regen[16]. In December 2020 we produced detailed DFES reports for our two licence areas:

- **North:** https://www.ssen.co.uk/WorkArea/DownloadAsset.aspx?id=20283
- **South:** https://www.ssen.co.uk/WorkArea/DownloadAsset.aspx?id=20282

Our DFES each year is co-created with our stakeholders. Over the near term the DFES projections are heavily influenced by the pipeline of projects and new developments that can be identified in the planning system, SSEN's connection database and by direct discussion with developers and stakeholders. Over the medium and longer term the projections will tend to reflect the underlying scenario assumptions and degrees of certainty supported by regional and national policies.

- The DFES assessment is a locally driven and evidenced-based analysis of the future energy scenario outcomes for a specific region. Stakeholder engagement and consultation is therefore critically important to inform the scenario modelling and test the future assumptions that have been made for the various building block technologies. Through engaging and consulting with a wide range of organizations and representatives we have been able to seek views and evidence in the following areas.
- Individual project development plans and timescales;
- Regional considerations for the potential uptake of specific technologies;

16 https://www.regen.co.uk/

- The viability of use cases and business models that would align with assumptions made around increased uptake or reduction of technologies connecting to the network;
- Specific regional policy, regulation and other decision making that could affect both the near-term and long-term trajectories for specific technologies, such as wind planning policy, electric vehicle charger deployment or heat pump uptake

To further enhance the scenario modelling and to allow stakeholder engagement to continue, we approached Local Authorities[17] with the results of the DFES projections to create a modified baseline scenario. The relevant data for each Local Authority (LA) was provided with a request for LAs to self-select the scenario which best represents the local (LA) view of the projection for four of the most impactful low carbon technologies. All Local Authorities have been asked to evidence their selection, with each being assessed in accordance with an open and transparent evidence assessment framework. Further details of our assessment framework is provided in Appendix B.

Our stakeholder engagement activity has enabled us to develop a number of key load-related assumptions:

- Renewable energy generation capacity is very likely to significantly increase;
- Unabated fossil fuel electricity generation is very likely to continue to decline;
- The shift to more decentralised energy assets will continue to some degree;
- The electrification of transport is already in progress and will accelerate;
- Hydrogen has a key role to play for industrial processes and some forms of transport
- Further energy efficiency deployment is vitally needed in both homes and businesses;
- The electrification of heat will increase although there remains a key uncertainty over the role that hydrogen boilers could play

Table 13 sets out a number of key stakeholder entities with whom we have engaged on our load-related proposals.

[17] This occurred in January 2021 and will continue as part of Final Business Plan submission and thereafter as part of regular business-as-usual planning processes.

Table 13 – key stakeholder engagement parties.

Sector-specific stakeholder consultations	We engaged with individual companies and industry representatives to better understand the projections for specific technologies. This included representatives many organizations, including but not limited to:
Engagement with the Scottish Government on DFES	At the end of October 2020, we met with Scottish Government officials to discuss the assumptions and DFES technology scenario projections for the North of Scotland licence area; and to road-test the DFES assumptions and some early modelling results. This helped to clarify how Scottish Government energy policy targets and decarbonisation strategies should be reflected in the DFES analysis. Through this engagement with Scottish Government in both the workshop and from reviewing the Climate Change Plan Update issued in December 2020, the DFES scenario analysis has been influenced (either directly or indirectly) by several targets, aims and milestones. Side bar 5 provides further details on how we have specifically accommodated Scottish government feedback. In addition, we have received written confirmation from Scottish Government supporting Consumer Transformation (CT) as the basis for a credible forward view of electricity distribution demand in the SHEPD licence area.

Side bar 5: How DFES modelling accounted for Scottish government feedback in our North license area

- **Electric vehicles & chargers**: Our Consumer Transformation scenario is consistent with Transport Scotland's projections on EV number;
- **Heating**: The Scottish government have a target for 50% of homes with zero carbon heating by 2030. Our Consumer Transformation and Leading the Way scenarios include 77% of homes with a heat pump variant by 2045; along with strong near-term uptake of air source heat pumps and a minimal adoption of hybrid heating, which is also consistent with Scottish government views;
- **Onshore wind**: Our scenarios align with the Scottish government target to have 50% of energy to come from renewable sources in Scotland by 2030;
- **Fossil fuel generation**: In all scenarios we have limited additional gas reciprocating engine capacity connecting in 2020s DFES decommissioning of all unabated natural gas generation by/before 2045. This ensure alignment with Scottish government targets. We have also removed island diesel generation from the scope of DFES, due to special role they play in maintaining island security of supply in Scotland
- **Hydrogen electrolysis**: Reviewed and reflected Transport Scotland Rail Decarbonisation Action Plan and the outcomes of the Hydrogen Assessment Project in electrolysis scenario uptake and geographical distribution.

Key trends in our scenarios

The full DFES documents for 2020 in the North and South should be consulted for a detailed analysis of technology evolution across our licence areas. In Appendix E we summarize some of the most important trends central to our analysis for the ED2 period.

Selecting our baseline scenario to drive ex-ante baseline investment proposals

Whilst we look across multiple scenarios to determine our investment requirements for the ED2 period and beyond our business plan submission is ex-ante based on a single set of scenario assumptions. The choice of scenario assumptions is defined with input from our stakeholders to represent a credible baseline trajectory of supply and demand change in the ED2 period. This in turn drives our network needs and investment proposals. We know of course the future could be very different to this projection, and so in Section 7 of this annex we set out our proposals to manage any resultant differences within the ED2 period.

In November 2020 and again in January 2021 we undertook sessions with our stakeholder community to present our DFES scenarios. We articulated key net-zero ambition levels such as number of EV chargers and heat-pumps. We also shared relevant data for each local authority, and devolved administrations; and asked stakeholders to self-select the scenario which best represents their view of the projection for four of the most impactful technologies. With the evidence received we were able to select a baseline

scenario which is representative of most stakeholder needs. In Table 14 we highlight key findings from this engagement and how it helped us select a baseline scenario.

Table 14: summary of stakeholder views to drive selection of baseline scenario to determine ex-ante investments

Engagement detail	Insights derived
Scottish Government (Energy and Climate Change Directorate) We collaborated with the Scottish Government through a series of bilateral meetings to identify the most appropriate Distribution Future Energy Scenario (DFES) to use as a baseline for ED2 planning	▪ The Scottish Government see that SSEN has a substantial role in supporting their statutory targets ▪ The Consumer Transformation DFES scenario is most closely aligned with the Scottish pathway to net-zero, although Leading the Way is also relevant ▪ For battery electric vehicle (EV) uptake, the expectation is that the future pathway will be between the Consumer Transformation and Leading the Way DFES scenarios ▪ For the decarbonisation of heating, while the Consumer Transformation scenario is closest to the ambition, there is likely to be a need to go further and faster than this. Reliance on hybrid heat pumps (from Leading the Way) does not correspond with their plans ▪ Renewable generation capacity is projected to be between Consumer Transformation and Leading the Way scenarios so the ability to flex these both up and down to meet the outturn is important
Local Authorities We provided LAs with DFES data for their area for EVs, Heat Pumps (HPs), PV, and battery storage and asking them to assess which DFES most closely matched their plans	▪ The majority of LAs (75%) who responded with selected Consumer Transformation or Leading the Way scenarios ▪ 10% of councils told us that they could not provide a response or could not do so yet ▪ Some LAs are working in regional groups on their climate change response, for example, Oxford city, Vale of White Horse, West Oxfordshire and South Oxfordshire; BCP Council (Bournemouth, Christchurch, and Poole) is producing a single plan with Dorset Council ▪ We are maintaining an open relationship with LAs to gather further evidence as their plans develop – this is likely to inform our use of uncertainty mechanisms
Local/community energy schemes, Consultants/Contractors, Local authorities We worked with Regen to engage stakeholders via separate online workshops for our North and South regions plus a	▪ It was noted by local authorities that local government can supply local information and help shape plans but SSEN needs to inform on requirements to meet 1.5C targets ▪ Local authorities expressed the view that SSEN should engage with them, local energy agencies,

follow-up survey to co-create projections for future network capacity based on several factors	local developers, and should look at Local Energy Plans ▪ It was also stated that SSEN needs to inform on what is necessary to meet 1.5c then understand what can be done locally to achieve this ▪ On several occasions local authority representatives thought local government needs to engage in conversation and provide as much evidence as possible. However, it was accepted they were short in resource and time and may not be able to provide sufficient evidence for reinforcement decisions ▪ 75% of local authority representatives that participated in the local network plan survey agreed with our approach of using credible 'base' scenario for electricity demand on the network and modifying where there is strong local evidence ▪ 88% participants in the same survey felt that adjusting network plans and investment aligned with local authority plans was a fair approach given investment costs will be socialised across consumer groups and geographies ▪ Stakeholders encouraged SSEN to collect evidence for network planning through public consultations with Community Councils

Summarising Table 14 **we are confident the Consumer Transformation scenario represents a credible scenario to underpin our baseline plan**. We believe this scenario has the necessary policy ambition, financial support, and delivery commitment, which is consistent with our stakeholder community, especially the democratically elected bodies in our area.

We know though that many of the targets and ambitions of our stakeholders are continuing to evolve and will be dependent, to a certain extent, on our agreed baseline plan. Where this is the case uncertainty mechanisms will provide the funding route for additional investment required.

Peak demand in our ex-ante baseline scenario

The modelling of peak demand in our scenarios is critical; and in the ex-ante baseline scenario it is central to our identification of network constraints and requirements for resultant investments. Peak demands typically represent the most onerous conditions under which the network must operate and so usually this defines the network planning criteria. Peak demands typically occur in the winter, but not always. In section 5.3 we provide further detail on how we use peak demand data to model network constraints, and in section 5.4 we describe the resultant process for optioneering on available solutions.

In this section we focus on articulating the building blocks to the peak demand. Understanding these building blocks is important as it provides an understanding of the underlying drivers of network

constraints and so can help reveal the availability and applicability of options available to manage the resultant constraint.

It is important to note that whilst the notion of a system-wide GB peak demand is often commented upon within industry its use for network planning for a distribution network is limited. This is because each part of the network and asset will experience a different peak, which often occurs at a different point in time from the overall peak. Furthermore, the notion of a licence area-wide peak demand is also misleading as all individual substations will experience a peak demand uniquely driven by the type and volume of connected technologies.

For this reason, we study the peak demand at various points on our network to understand the investment implications. Figure 8 provides a case study example of the modelled peak demand at typical secondary substations on our network in 2028 for the Consumer Transformation scenario. The figure highlights the impact of two key components of future demand, Electric Vehicles (EVs) and Heat Pumps (HP). It highlights that in this scenario at the LV feeders the impact of EVs will have a more pronounced impact on peak, whilst at the HV feeders the impact of HPs is more pronounced. This impact of diversified charging profiles for EVs is the biggest factor contributing to the change in impact between LV and HV. With higher volumes of EVs feeding into the HV feeder and the impact of smart charging the peak impacts can be tempered; whilst for HPs the level of diversification is lower.

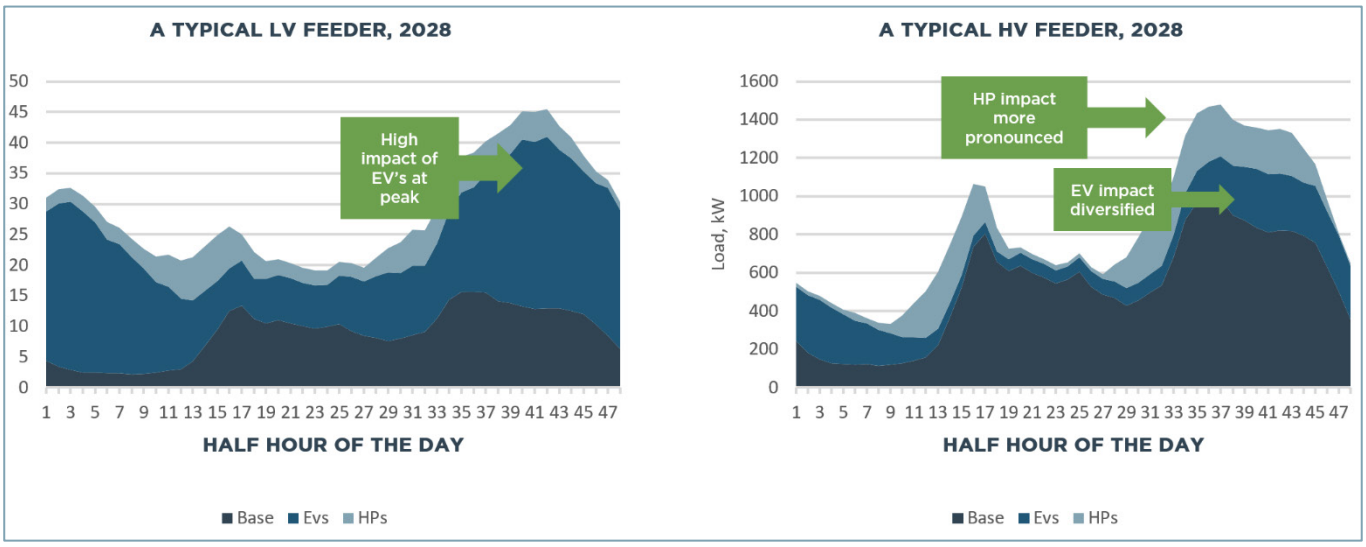

Figure 7: Example of peak demand at typical secondary substations

When undertaking a future looking assessment of peak demand two components are vital to understand:

1. The existing peak demand at a particular point on the network
2. how different technologies in the scenarios contribute to peak demand

The extent to which we can accurately determine the existing peak demand on our network differs at the various levels of the network. For the primary network our level of network monitoring is more extensive than the secondary network. This means that for secondary network alternative approaches are required to estimate the peak. At SSEN we have made use of a range of techniques to do this, including machine learning, data cleansing and repair and geospatial outlier detection in order to generate a complete picture of conditions on all of our secondary assets. This is described further in this section.

To understand the how different technologies in our scenario add to (or adjust) the peak demand we need to understand four factors:

1. The distribution of different LCT types connected across the voltage levels on our network (e.g. a commercial car park EV rapid charge point may connect directly into a low voltage secondary transformer rather than be connected to an existing LV feeder)

2. The number of LCT units (MW) of each type connected at each point in the network, according to the scenario

3. The size or rating of the technology type connected at each point on the network

4. The profile of demand for the LCT type connected at each point on the network

Using the above four factors and the existing peak demand we can calculate the future peak demand at a particular point on the network according to the high-level equation:

$$\text{Future peak demand} = \text{Existing peak demand} \pm \sum_{\text{technologies connected}} (\text{Demand profile} \times \text{number of units of technology} \times \text{standard unit of technology})$$

The remainder of this section is devoted to articulating our approach to setting each of these components at the different voltage levels.

Existing peak demand

At primary voltage levels we have extensive monitoring which means we are able to provide an accurate view of existing peak demand at key points on the network, and to use this as the basis for future demand scenarios.

At the secondary level (11kV and LV) we require highly granular assessments (down to street level) of future deployment of LCT, together with an innovative, data-led, analytical approach in order to identify local community network 'hotspots. These hotspots form the basis of further, more detailed, network studies as the basis for the HV and LV ED2 investment plan. Furthermore, we have used advanced artificial intelligence and additional data analytics to help fill and validate data gaps at HV and LV with a high degree of confidence[18].

Historically, and for good economic reason, the secondary voltage network, and the associated network assets, do not have the same coverage as the primary voltage network – particularly in terms of data, information, monitoring and control. This 'need' is rapidly changing. Improved understanding and control of the secondary network is a prerequisite for the development of a distribution system which can accommodate LCT and facilitating the markets needed to achieve net-zero. In our LV monitoring strategy, you can find out more about how we propose to increase our monitoring.

The roll-out of enhanced monitoring is a key deliverable for the ED2 period; however an approach to determining current peak on the secondary network is needed to develop the ED2 ex-ante plan submission. Our three-step approach to determining secondary network demand has applied machine

[18] Our methodology and approach for determining our expenditure plans on the secondary networks was independently reviewed and assessed by TNEI in February 2021.

learning techniques to determine the loading on the network using a combination existing data monitored data on the secondary, smart meter data, customer profile data and known information on network topology to derive demand based on common customer profiles.

The three steps applied to calculate the demand on the secondary network:

1. Bottom-up approach modelling individual customer behaviour, making use of industry standard models;
2. Top-down approach that starts from known aggregated demands at higher voltages and distributes these among customers at lower voltages; and
3. Review of maximum demand indicators, where available ground-mounted transformers, to complement our bottom-up and top-down assessments

Figure 9 shows the confluence of the bottom-up and top-down approaches.

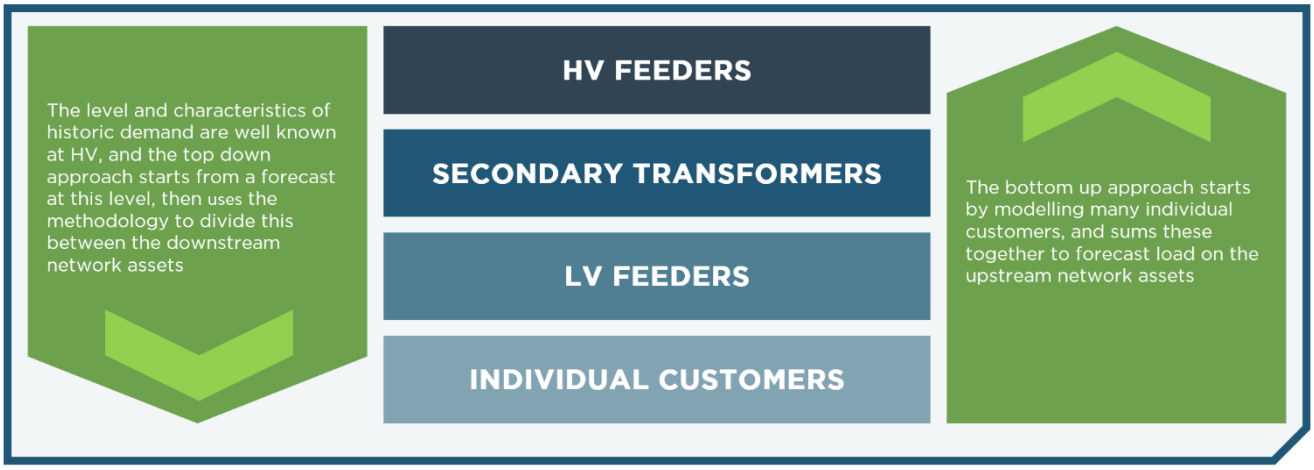

Figure 8- Bottom up and top down approaches to HV & LV demand estimation

The bottom-up approach calculates the demand using a combination of customer data and standardised profiles of customer usage. We achieved this using a combination of customer Estimated Annual Consumption (EAC) data and half-hourly profiles from EA Technology's WinDEBUT software[19]. These profiles are based on the ELEXON customer profile classes shown in Table 15.

Table 15 – Elexon profile classes

Profile Class	Description
1	Domestic Unrestricted Customers
2	Domestic Economy 7 Customers
3	Non-Domestic Unrestricted Customers
4	Non-Domestic Economy 7 Customers

[19] WinDebut provides industry-standard consumption shapes for different type of customers. When multiplied by an estimated annual consumption in kWh, they produce a scaled shape of consumption power in kVA.

Profile Class	Description
5	Non-Domestic Maximum Demand (MD) Customers with a Peak Load Factor (LF) of less than 20%
6	Non-Domestic Maximum Demand Customers with a Peak Load Factor between 20% and 30%
7	Non-Domestic Maximum Demand Customers with a Peak Load Factor between 30% and 40%
8	Non-Domestic Maximum Demand Customers with a Peak Load Factor over 40%

This method enabled us to estimate the demand of each of our customers and scale-up to calculate the current load on our network assets. We recognize the importance of applying diversity when assessing LV feeders and HV/LV transformers to allow for differences in customer peaks. Figure 10 provides a typical example of how diversity has been applied in our LV load calculations.

Side bar 6: Definition of demand diversity

In network planning, the peak loading of assets is critical. This is driven by the simultaneous use of the network by many customers; however when considering large groups of customers, a key factor is that they do not all use the network in the same way at the same time; this leads to a 'smoothing' of demand over different time periods that occurs as more and more customers are connected to assets further up the network. This is known as diversity, and substantially reduces network requirements compared to if all customers' peak usage of the network happened concurrently.

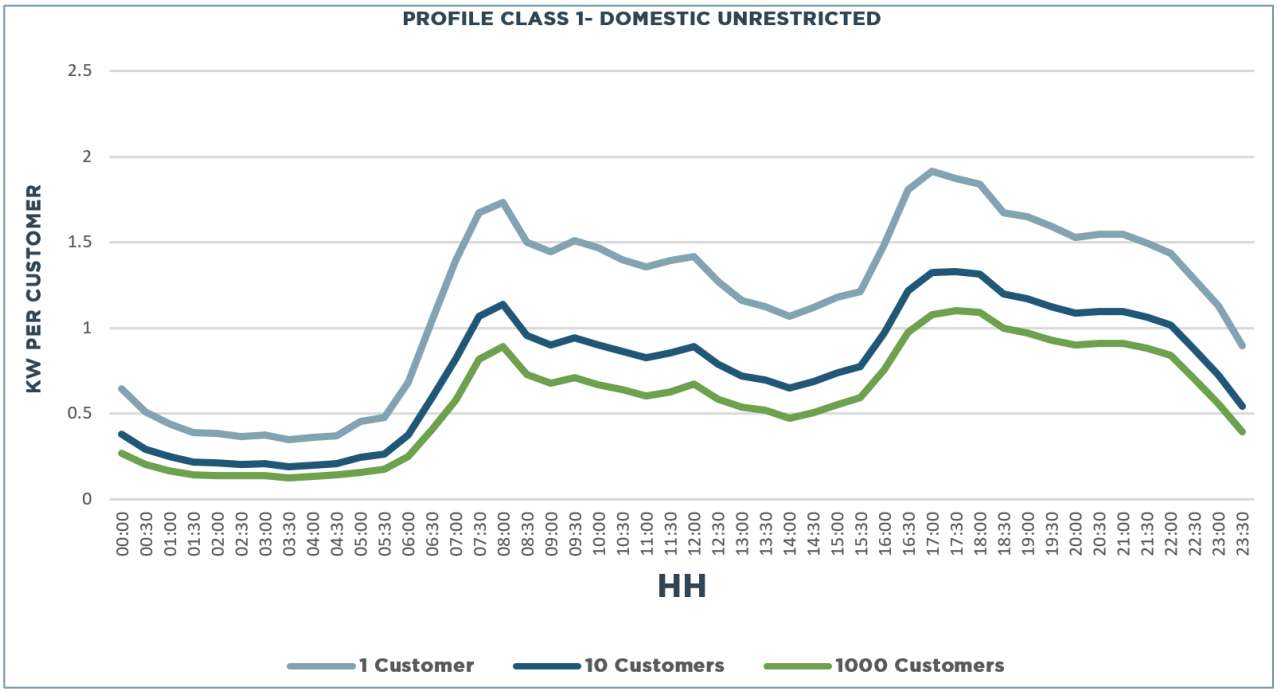

Figure 9: How diversity is applied on our LV load calculations

Our top-down approach used the winter maximum demand recorded from our HV feeder circuit breakers. This is a data set we have relatively high coverage off across the network. The sum of customers EAC, per LV feeder and distribution transformer respectively, is used to proportion the HV feeder demand across the LV network.

Bringing the bottom-up and top-down data together with the maximum demand indicators, on ground-mounted transformers we are able to determine an average demand on the LV assets on the network. Available LV monitoring data is used as a benchmark to validate. Figure 11 illustrates the difference between the LV substation monitoring data and the developed load estimate methods. We have found that the average between the approaches is relatively consistent to the data available from LV monitoring. Therefore, the average between the approaches is used as the baseload for LV feeders and secondary distribution transformers.

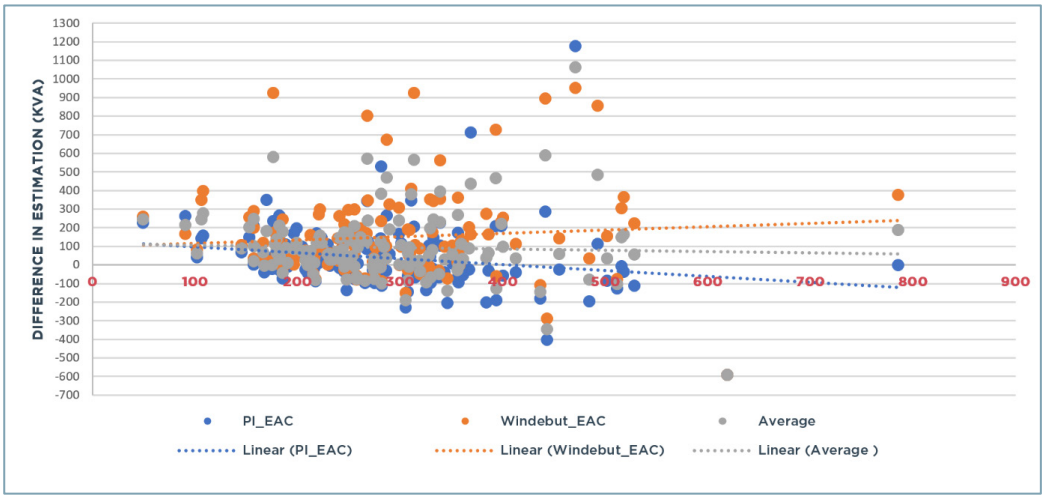

Figure 10 – LV demand calculation approaches.

Technology demand profiles

A technology demand profile represents the typical underlying utilization characteristics of the technology which in turn help us to understand the contribution it has on peak demand. Each technology has a different utilization profile, and, in some cases, there can be sub-sets of utilization profiles. For example, EVs have complex potential behaviour. They have the characteristic of being a moveable source of demand, which can have different impacts on the network depending on the charging mode- the underlying model we've employed holds different profiles for eight 'types' of charging to reflect this, as shown in Table 16. In Table 17 we outline key technology types and the source of the underlying peak profiles used.

Table 16: Different modelled charging methods that contribute to peak demand forecasting

Charging mode	Description
Domestic off-street	Charging on private driveway/in garage
Domestic on-street	Charging on a public street outside home
Workplace	Leaving EV connected at workplace
Fleet	Where EV is part of a commercial enterprise, such as a hire car or taxi

En-route local	Where charging occurs during a local journey
En-route national	Where charging occurs during a longer journey, ie using motorway services
Destination	Where charging occurs at a location a consumer is visiting (and the purpose of the visit is unrelated to charging)
Car park	Where charging is provided at a car park

Table 17: Sources for demand profiles for key technologies in our analysis

Technology	Source for demand profile
Domestic development	Profiles are taken from UK Standard Load Profile used for utility pricing (domestic = class 1) scaled to give an average power consumption of 0.53kW, which equates to an annual electricity consumption of 4600kWh (typical for a higher consumption property)
Non-domestic development	Profiles are taken from existing customer connected to our network; we have few different types of non-domestic developments
PV, gas, and diesel generation	Profiles are representative of existing customer connections
Battery & other generation	Flat profiles are used
Onshore wind and hydropower	Profiles are representative of existing customer connections
Air conditioning	Profile taken from Treidler, B. and Modera, M. (1994), Peak Demand Impacts of Residential Air-conditioning, Proceedings of ACEEE 1994 Summer Study on Energy Efficiency in Buildings
EVs	Profiles are sourced from the 2019 Elementenergy **Electric Vehicle Charging Behaviour Study** for National Grid ESO, with SSEN modifications applied to align with Regen data
Heat pump	Profiles taken from **Customer-Led Network Revolution** trials

Number of units of technology and distribution of technology types connected

The number of units connected is a function of the scenario trajectories and is fully described in each of our DFES 2020 documents for **North** and **South**. The distribution of technologies by voltage level is in accordance with Table 18.

Table 18: Technologies connected by voltage level

Connection point	Technologies connected
Primary to 11kV substation	▪ Electricity generation except rooftop PV ▪ All battery storage ▪ Hydrogen electrolysis ▪ Air conditioning ▪ New housing and commercial property developments ▪ EVs – HGVs, buses, motorcycles.
Low Voltage secondary substation 'Transformers'	▪ Commercial EV chargers (Car park; Destination; En-route local; En-route national; Fleet; Workplace) ▪ Non-domestic heat pumps

Feeder lines to consumers	▪ Electric Vehicles – Cars ▪ Electric Vehicles – LGVs ▪ Domestic off-street chargers ▪ Residential on-street 7kW chargers ▪ Heat pumps (hybrid and non-hybrid) ▪ Small scale Rooftop Solar < 10 kw ▪ Direct electric heating

Table 18 shows how the scenario projections for LCT have been distributed down to the level of secondary distribution 'transformer' sub-station, or to individual LV feeder lines which serve individual or small groups of consumers. This level of granularity corresponds to post code or street level analysis. Although the distribution of technology deployments is based on high-level scenario assumptions and distribution factors, it still allows for our network planning function to consider the potential impact of demand and technology changes on the low voltage network, and to understand the scale and range of network reinforcement that might be needed.

The distribution factors that underpin the spatial analysis, are based on data gathered from a wide range of datasets including Ordnance Survey Address base, road traffic flow data, Census Output Area data including affluence and demographic data, postcode statistical data, and individual property Energy Performance Certificate data. The distribution analysis uses affluence as one of the key factors driving the uptake of low carbon technologies. This is based on previous new technology deployment trends and empirical evidence that the uptake of low carbon technology has, to date, tended towards more affluent areas. For EVs, it is also based on the very practical consideration that, in the near term at least, the availability of off-road parking is a key driver for EV adoption.

To provide a degree of balance in the analysis the following approach has been taken.

- Affluence is considered a key distribution factor in the short term for Consumer Transformation and Leading the Way. For the Steady Progression and System Transformation scenarios, which have lower social interventions, affluence remains a stronger driver in the medium term;
- Over the medium and longer term, for the higher ambition scenarios, the impact of the affluence distribution factor is reduced, and an assumption is made that the deployment of LCT technologies will become more ubiquitous and will follow the underlying factors;
- For solar PV and heat pumps, the scenarios specifically include a social housing weighting factor to counter purely affluent areas. This social housing impact has previously been documented in Regen's DFES studies;
- For the more ambitious scenarios, from mid to late 2020s, the underlying assumption is that EVs will become ubiquitous. Therefore, the growth in demand for EVs in both on street and off-street areas begins to increase at equivalent rates

Annual energy consumption by LCT type

We have used a series of industry standard data points to inform the annual energy consumption of different key technologies contributing to the peak demand. These values are converted into a peak loading contribution using the technology demand profile, noted above. In Table 19 the standard units of annual energy consumption by technology is shown.

Table 19: Standard units of annual energy consumption by technology connected and peak.

Technology	Standard annual energy consumption (kWh)	After diversity peak demand (kW)
Average household	3200	1.9
Average household with 'Economy 7' heating	8500	4.9
Heat Pump electric backup (average winter)	3.5	3.4
Heat pump gas backup (average winter)	3.5	3.2
Direct electric heating (average winter)	3.5	3.2
EV at home charging	7	7
EV destination and car park charging	15	4.2
EV workplace and depot	36	4.6
EV en-route - national and local	150	51.8

Reconciliation of DFES and FES

We have developed a comprehensive DFES framework to represent the needs and feedback of our local stakeholders in our licence areas. This framework was built this from a starting point of a central framework of scenarios developed by the Electricity System Operator (ESO). Each DNO for their licence areas has undertaken a similar, yet independent, process. However, there is an inherent risk in the DFES envelope that each company builds that when summed the total is not aligned with the national trajectory set within the envelope of the FES scenarios. This is further complicated if further regional adjustments are made to the scenarios post-publication for the purpose of setting an ex-ante plan.

To measure alignment between our DFES envelope and the national FES we have compared our data on key demand growth technologies for the ED2 period, namely EVs and Heat Pumps to a disaggregated view of the National FES from data sets published on the ESO website by DNO. Figure 12 shows the comparison for all companies between reported number of EVs and HPs in DFES publications and the national FES disaggregated view. For SSEN we have not adjusted our DFES range for the purpose of preparing our ED2 plan, therefore as demonstrated by Figure 12 we are fully aligned with the national FES view on our projections of heat pumps and largely aligned with projections on EVs.

Our higher scenario projections for EVs assumptions are outlined in our DFES publications. Given our limited visibility of other company business plans we are unable to comment on whether the DFES ranges publicly reported have changed for the purposes of their business plans.

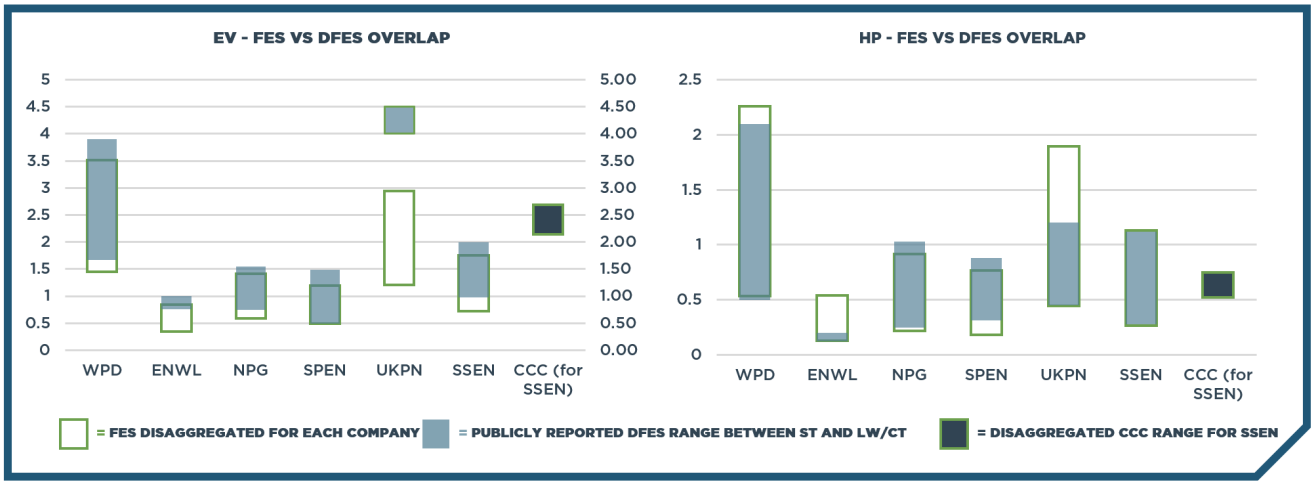

Figure 11: Comparison of DFES to National FES on key technologies

5.3 GENERATING NETWORK REQUIREMENTS AND OPTIONS

In Section 5.2 we describe the changes to supply and demand connected to our networks. We focus on articulating how we use scenarios co-created with our stakeholders to understand credible pathways to reach net-zero. We articulate why we think Consumer Transformation is credible as a stakeholder supported scenario on which to base our ex-ante plan. Finally, we articulate how we determine the peak demand and reconcile our scenario view with the national FES.

In this section we describe how we generate a view on future network constraints in the scenarios and the options available to remedy. In section 5.4 we describe the optioneering process to select the most economic and efficient investments.

Principles of defining adequate network capacity

In order to ensure that sufficient network capacity is available where and when needed to actively support our local communities in contributing to the achievement of net-zero, our approach is to design the network whilst adhering to three criteria:

1. Ensure compliance with industry security planning standard P2/7 and related regulation
2. Invest in local network capacity sufficiently to meet customer needs whilst preventing overloading of our equipment and avoiding other network constraints – both now and in the future
3. Ensure that creating additional capacity for LCT uptake does not adversely impact existing network reliability.

Each of these elements of our policy and approach is described further below.

Compliance with industry security planning standards

We have a licence condition to plan our electricity distribution in a way that provides an acceptable level of security of supply. Primary consideration is compliance with security planning standard P2. The P2 planning standard defines the level of spare capacity ('redundancy') that must be provided at each level of the network and for increasing groups of load. The network planning standard aims to provide electricity supply reliability commensurate the with the amount (MW) of group demand or generation. P2 thus influences the number of discrete circuits or transformer units needed to supply communities and neighbourhoods. Load-related expenditure improves our network resilience and minimises the frequency and duration of outages our customers experience.

Compliance with P2 security planning standard is a key driver of our investment proposals at EHV where it is usual to duplicate network components to ensure group demand can be supplied during fault conditions (forced outages).

In addition, it is a licence obligation that we comply with other industry codes and engineering recommendations such as G99 and G100 for embedded generators in our overall design, which may impact specific load related works. Safety is also of paramount importance and there is an ongoing requirement for compliance with several statutory instruments and regulations, such as the Electricity Safety, Quality and Continuity (ESQCR) Regulations 2002.

Invest in local network capacity sufficiently to meet customer needs today and the future

Whilst our policy and approach at EHV is significantly driven by compliance with deterministic security planning standards as peak demand is forecast to increase, at the lower voltages, especially LV, our proposed baseline investment] is driven by the need to supply an increased level of demand associated with the connection of up to over half a million EV charge points and over half a million heat pumps by the end of ED2.

Whereas much of the investment at EHV aims to ensure continuity of supply to large groups of customers in the case of a fault on the EHV network, the investment at the lower voltages is to ensure sufficient local capacity to enable connections for EV, heat pumps and other types of LCT to be made in the first place. Failure to invest in local capacity would risk us failing to deliver on a key strategic objective to facilitate accelerated progress to net-zero.

Ensure that creating additional network capacity does not adversely impact existing network reliability

Our customers and stakeholders tell us that they value reliability of electricity supply highly, but only where this is delivered for a reasonable price and where it represents value-for-money.

The reliability of supply experienced by our connected customers depends not only on the resilience of the network and its ability to withstand the environment, but also in the ability and capacity of our business to respond and repair when things go wrong. It's of the utmost importance that the level of service and reliability received by our existing customers is not compromised or adversely impacted by the reinforcement and augmentation of our distribution system needed to support the uptake in LCT.

Against these three principles, the network is appraised, with a distinction in methodology between EHV and the HV & LV voltage levels.

Finding the constraints in the Primary Network

The Primary Network represents the 132kV and 33kV networks in SEPD and the 33kV network only in SHEPD. It is also referred to as the EHV. Our methodology used to identify EHV load-related expenditure is consistent across both licence areas although data was obtained from separate, network specific, DFES projections. Our process combines existing network models used for the Long-Term Development Statement (LTDS) submission, contracted connections and associated reinforcement data, and the demand and generation projections from the DFES. This data allows us to replicate the scenarios of the DFES and our modified baseline scenario within a system model for each year of the ED2 price control. At **EHV** (132kV and 33kV) we have undertaken **comprehensive load-flow modelling to assess the prospect of future network security 'non-compliances'** – based on the range of input scenarios set out above.

Using power system analysis software, we have assessed our system for the ED2 period using the following:

- **thermal assessment** – to identify any assets which may overload thermally due to the increase in demand and/or generation. Thermal overloading can decrease the expected lifetime of an asset,

trip system protection leading to customer outages and increase the likelihood of asset failure if overloaded for a prolonged period.

- **voltage assessment** – to identify any areas of the network which may experience high or low voltage beyond statutory limits. This can be caused by the increase in demand and/or generation. High voltages can result in damage to equipment and can trip system protection leading to customer outages. Low voltage can also cause damage to motorised appliances and will increase losses on the system.

- **fault level assessment** –to identify any areas of the network where the fault level exceeds 95% of the rating of system protection due to the increase in demand and/or generation. If a fault occurs and the fault level exceeds the interrupting current rating of the connected switchgear, this may cause severe damage to assets and more importantly risk the safety of anyone around these assets at the time of fault. This assessment has been run at worst case (maximum demand/maximum generation) and any fault levels identified to be more than the switchgear rating has been considered for reinforcement.

These assessments were carried out for normal operating and all credible first and second outage conditions where required, highlighting the system constraints and limitations by year, season and scenario.

Finding the constraints in the Secondary Network.

Automated connectivity and rating analysis

A key issue to overcome in evaluating the investment needs of our lower voltage network is the vast number of assets involved (which is on the order of hundreds of thousands units/kilometres). This issue is compounded by the lack of historical measurement in the LV network, and uncertainty in the precise connectivity of the assets in many cases.

Connectivity describes the actual physical structure of the network - which transformers connect to which feeders, and which feeders serve which customers. This is critical to creating an accurate forecast of the loading each component experiences and to understand a transformer's loading patterns, particularly its peak load, an idea of how many customers it's serving is required, which necessitates knowledge about the route of the feeder. Figure 13 represents our machine learning process for fully understanding these connections. Note that the development and finalization of this model is an ongoing activity, which is further detailed in ***IT and Digitalisation (Chapter 05)***.

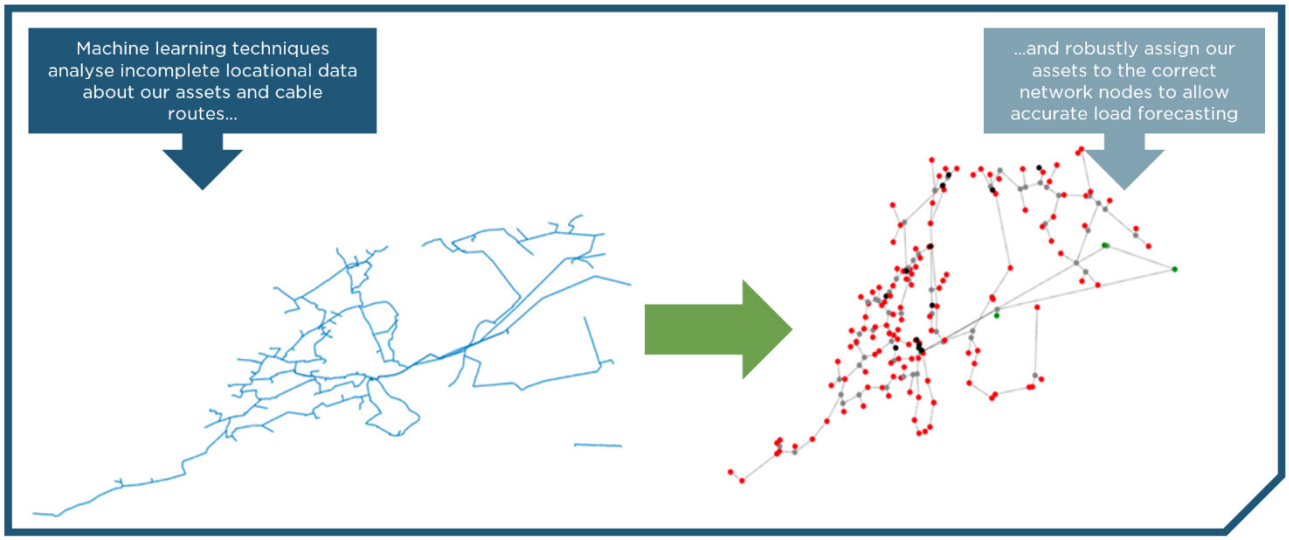

Figure 12- Representation of process for connectivity modelling.

All of these issues have been tackled through our ED2 Load Model project, which cleansed, repaired and leveraged existing data from multiple sources to create a clear and robust picture of the most likely connectivity and rating of every network component using a range of advanced data analytics approaches including machine learning and geospatial outlier detection. This complete, validated view of our networks allowed the peak demand forecasts previously discussed to be applied to uncover the constraints throughout our lower voltage levels.

Determining constraints from demands

With the baseline load calculated as described, we have added the granular forecast demand drawn from the DFES work described in section 5.2. This additional demand has been built up from the component demands allocated to each individual LV feeder. Through comparison of forecast loading to nameplate circuit capacities, we have identified a hotspot list of 300 HV circuits with potential risk of thermal overload in the ED2 period. We have modelled these on power flow analysis software to assess thermal, voltage and fault level, in a similar manner to the EHV assessments as described in the preceding section on finding constraints in the primary network. We found approximately 345km of HV circuit that requires investment.

For secondary transformers and LV feeders, we have been able to identify future thermal constraints, by comparing the modelled nodal demand to the nameplate capacity of the assets serving that node. If the forecast load exceeded 120% of nameplate rating for outdoor ground or pole mounted transformers; and 110% of nameplate rating for indoor ground mounted transformers. The total number of secondary transformers requiring investment by the end of ED2 is 11,348 in SEPD and 7,569 in SHEPD. The total number of LV feeders requiring investment by the end of ED2 is 6,123 in SEPD and 2,018 in SHEPD.

Constraints by scenario

The first-pass assessment and subsequent categorization has allowed us to identify and prioritize constraints on our network before considering options to address each of these, as shown in Figure 14.

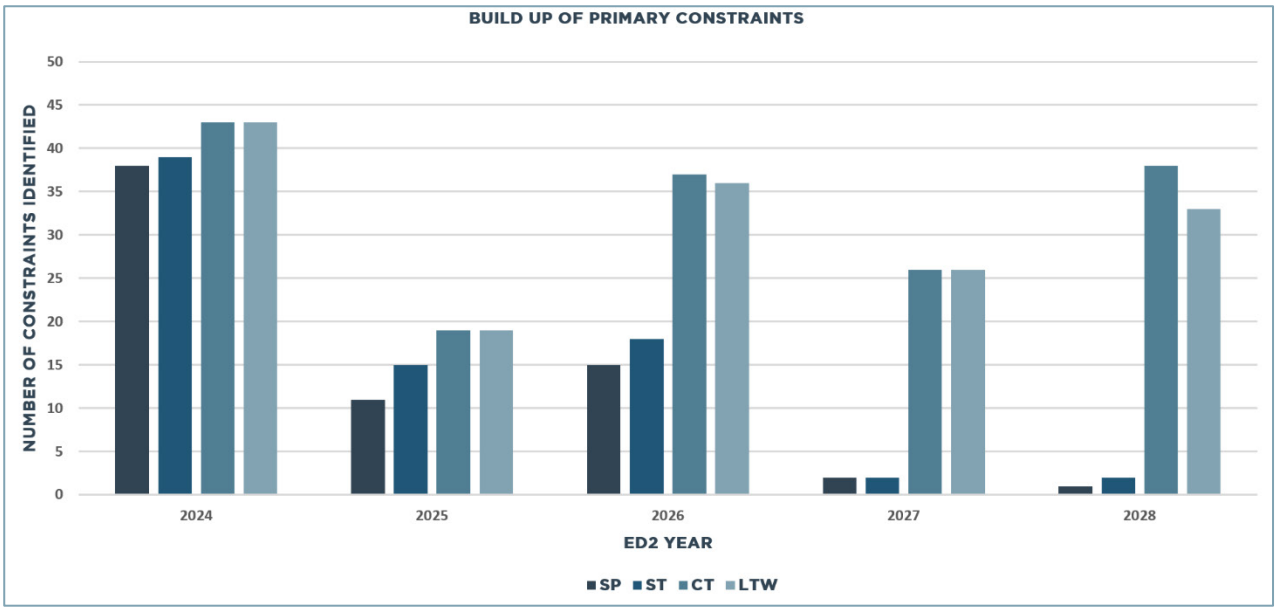

Figure 13- Build-up of primary constraints against different scenarios

Primary constraints included 163 thermal, voltage and fault level issues on our primary network based on assessment of our baseline scenario. To allow our plan to adequately factor in the uncertainty in our plan, we have also studied how these needs vary if a different scenario outturns, analysing Steady Progression, System Transformation, and Leading the Way scenarios to gauge how wide a range of requirements could be present. Within the ED2 period, SP requires 43% fewer interventions through this assessment, reflecting the slower rate of LCT uptake in that scenario, manifesting significantly in 2027 and 2028, where CT and LTW scenarios drive many more issues than found in SP or ST due to the much-accelerated uptake of LCTs. Investigation of the scenarios shows that SP and ST do reach the same levels of LCT penetration as are present in CT 2028, but well into the 2030s- it is therefore anticipated that should those scenarios outturn, the same constraints would eventually require intervention, but on a longer timescale.

At the secondary network, the assessment also found a step change between the two more aggressive scenarios, LtW and CT, then in the case of SP and ST; again LCT uptake is the critical factor, driving the need to intervene on a very significant quantity of network.

Across HV and LV, and transformers, OHL and cable, significant probability of overloading occurring was revealed if demand growth tracks to the CT or LtW forecasts; LCTs being integrated in domestic settings, and therefore acting directly upon LV feeders, will challenge many LV cable routes contributing to the circuit lengths and transformer volumes shown in Figure 15 and Figure 16 respectively.

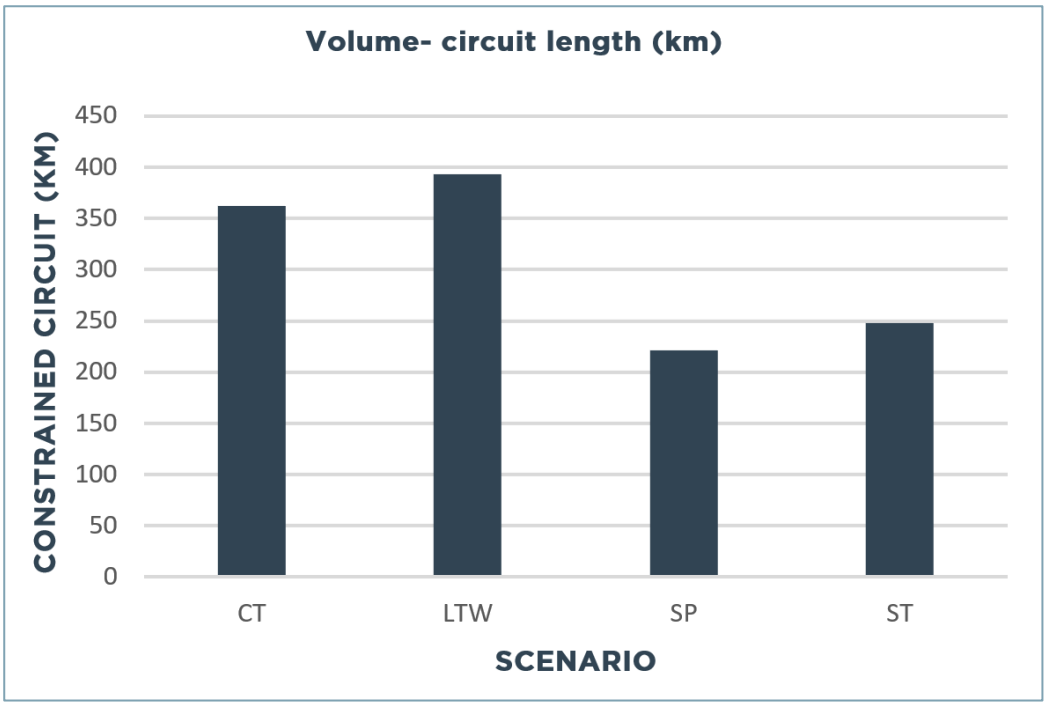

Figure 14 - Total circuit length (OHL and cable at HV and LV) requiring some intervention

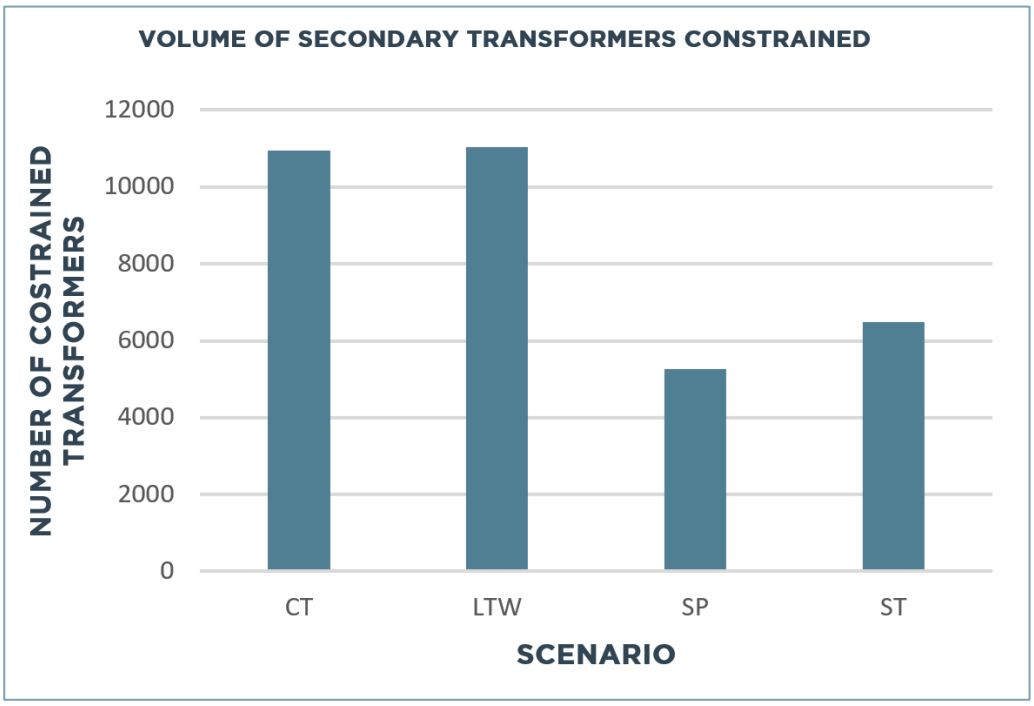

Figure 15- Total number of transformers on the secondary network requiring some intervention

Monetised impacts by scenario

The identified constraints associated with the different scenarios have been used to assess the potential expenditure needed for each pathway. This was done before significant optioneering. For each constraint identified, the most likely conventional intervention, based on historical deployment, was selected. Typically, this follows a comparatively straightforward asset upgrade strategy. This 'first-pass' process

leads to the cost estimates shown in Figure 17. As would be expected, the two pathways with accelerated LCT uptake require much more expenditure within the ED2 period to ensure sufficient network capacity and facilitate an increased number of new connections and connection service upgrades. The need is considerably lower for SP and ST for the same period, but still exceeds £300m for load related expenditure[20]. (e).

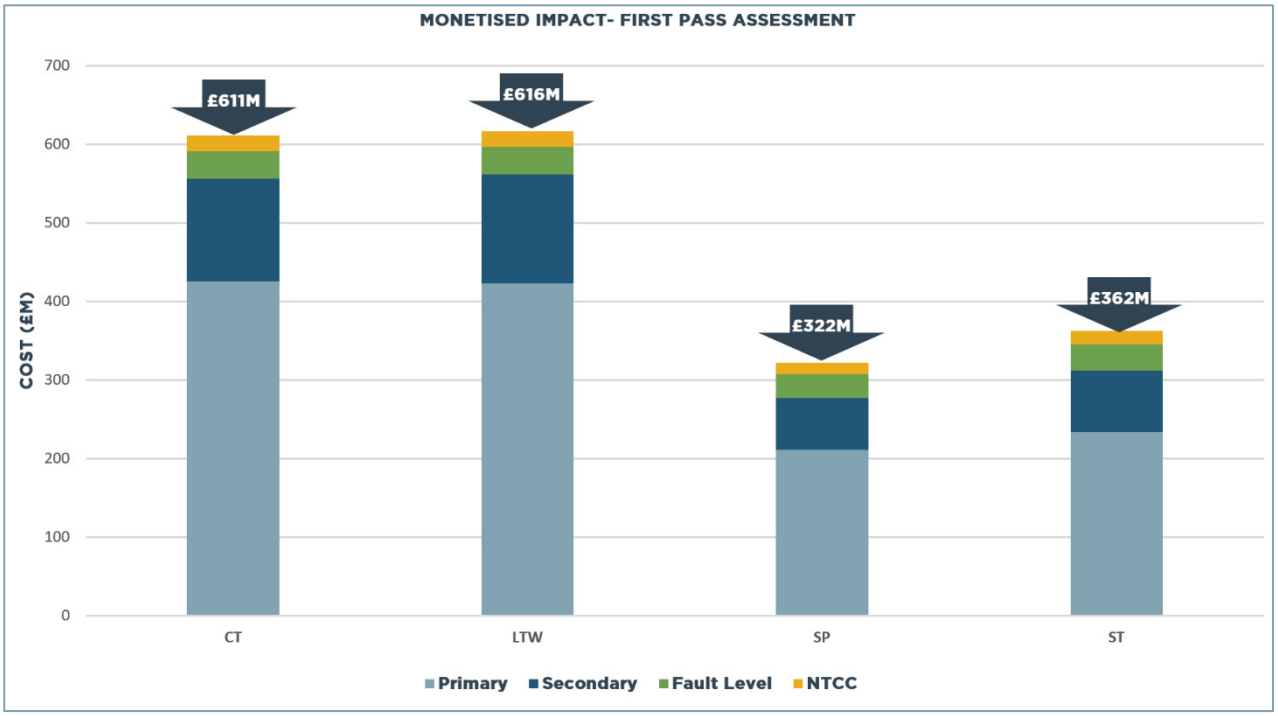

Figure 16- Monetised impact of conventional approach to addressing identified constraints

While these figures are pre-optioneering, they still represent a credible set of costs to address the volume of issues that could arise on our networks; this is why the engineering assessments and subsequent optioneering are so critical to generating consumer value by outperforming these preliminary set of solutions.

Generating intervention options for identified requirements

For the constraints anticipated across each voltage level studied, and for each credible future pathway, we have identified options for providing the capacity shortfall. In addition to conventional solutions (such as asset-based reinforcement), we have ensured that both flexibility and innovation have been prioritised in the assessment and justification process.

- **Flexibility first:** the application of a flexible solution is considered for all constraints identified on our EHV system[21], as part of our broader actions on implementation of Whole Systems thinking[22]

20 Excludes connection-related reinforcement costs, triggered by new or additional customer load.

21 The flexibility option is detailed on a case-by-case basis within individual EJPs.

22 Cross reference to Whole Systems (Annex 17)

- **Leverage ED1 Innovations:** We have sought to use technologies and solutions that have been successfully piloted during ED1 to ensure benefits for consumers are fully realized.

To provide a baseline for comparison, all technical assessments include a 'do minimum' option. This usually represents the lowest-cost conventional solution to ensure compliance with the required engineering standard (e.g. P2/7).

The following options are considered for each intervention requirement wherever practicable:

- Conventional asset reinforcement to provide an increase in capacity - i.e. replacement of an asset with one of larger capacity
- Installing additional conventional assets, such as adding a parallel circuit
- Reconfiguration of the network (often in combination with asset replacement or addition)- for fault level issues, for example, splitting busbars to reduce fault level
- Whole system solutions, such as meeting distribution network needs through works on the transmission network
- Innovative solutions, including those deployed in ED1
- Flexible solutions that allow the deferral of any other solution were always considered

All selected solutions have been cross-checked against our other intervention plans to ensure coordination with no double-counting of solution expenditure (e.g. load-related and non-load related). More detail on these solution types are provided in the following sections.

Applying the 'Flexibility First' principle

Our ED2 Whole System approach reflects our plan to embed a more collaborative approach to delivering customer benefit and value. We aim to achieve this through three main sets of actions, as set out below.

- Reflecting on progress and lessons learned - including assigning internal accountability for Whole System and adopting a more regional approach to working with local authorities;
- Reviewing internal processes to embed and promote Whole System thinking, such as working with SHET to review Whole System solutions and promoting Whole System thinking through increased reporting of initiatives; and
- Embedding Whole System thinking into decision making including by producing and implementing guidance on how and when to use the ENA Whole System CBA.

There are two principal manifestations of whole systems thinking in our load-related activities; working with electricity transmission networks to apply a flexible approach to the use of capacity, including at the transmission-distribution interface; and procuring flexibility from market participants who may in turn support the development of flexibility from a wide range of sectors[23].

[23] We provide further details on our ED2 transition pathway in our paper Whole Systems (Annex 17).

Procuring flexibility to address network requirements

We have now adapted our standard processes for optioneering to incorporate a more proactive approach to procuring flexible solutions; extending the use of flexibility to our entire network - ahead of need - to existing (or potential new) flexibility providers across our entire network area. This allows us to better assess the opportunities to purchase flexibility and to respond more quickly as and when the need for a flexible solution arises. The location of all network congestion (constraints) is visible to stakeholders on an independent marketplace for buying and selling smart grid flexibility services. We continue to encourage potential flexibility providers to register for details of future opportunities. Figure 18 shows the types of flexibility services procured to date and the associated benefits and outcomes. These existing procurement exercises form the basis of our £150/MW/hour availability cost assumption, and £150/MWh utilisation cost

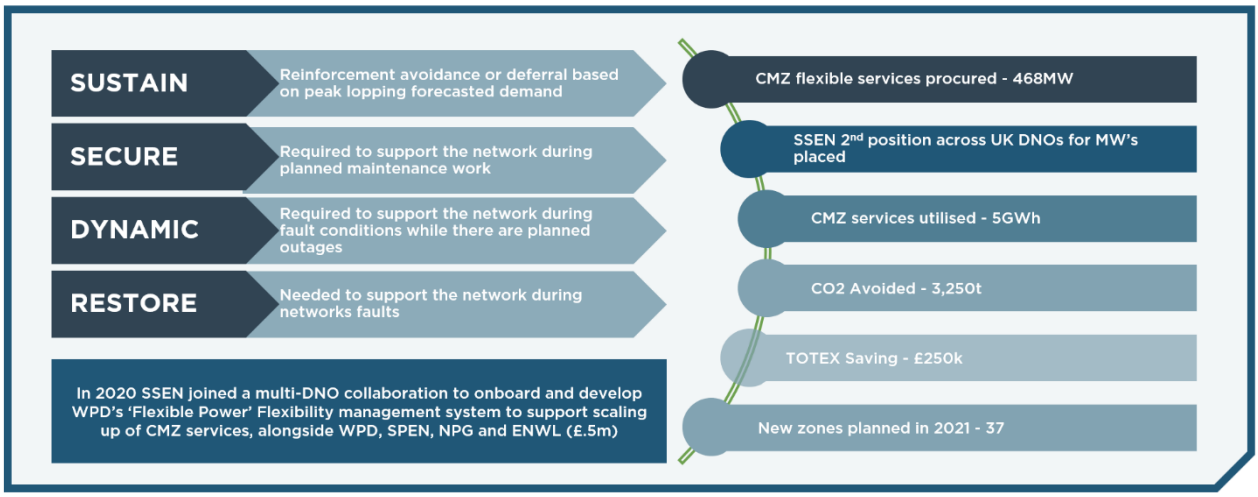

Figure 17- Structure of Flexibility services procured

The network constraints identified through the first-pass assessment form the basis of our 'Global Call for Flexibility'[24]. The purpose of this work is to inform and obtain flexibility interests and potential flexibility prices from service providers. An important first step is our request for 'registration of interest' for flexibility. This is undertaken ahead of formal procurement for flexibility and allows us to accommodate the uncertainty associated with scheme delivery each year. We will be undertaking formal engagement with the flexibility market during the ED2 period as part of our business-as-usual investment decision-making process. Our work in this arena allows us to credibly assess and compare flexibility options for inclusion in our baseline plan.

Working with Transmission companies

We have worked closely with our Transmission partners including National Grid Electricity Transmission, Scottish Hydro Electricity Transmission and National Grid Electricity System Operator on our Load related plan. Their invaluable feedback has helped us improve the intervention options for a number of load-related schemes.

A typical example is the collaboration with our partners on the Fleet-Bramley 132kV network to manage the demand group growing beyond Class E (1500 MW). We also worked closely with the Transmission

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

Operators to align the load forecasts at the T-D interface the results from which form our Transmission Connection Point Charges for ED2.

ED1 Innovations

There are several key innovation projects and learnings on which we have drawn in the preparation of our load-related expenditure, including those shown in Table 20. Transferring value and benefits from innovation projects and initiatives into our business-as-usual investment decision-making continues to be high priority for the remainder of ED1 and into ED2 and beyond.

The innovations most relevant to our load-related expenditure proposals are associated with the procurement and use of flexibility and monitoring of LV circuits to better understand potential overloads and help refine and improve forecasts and projections. The list of innovations is provided in Table 20, where we also set out the customer benefit and provide a link to more detail of specific innovation initiatives.

Table 20 - Innovations which have influenced our load-related expenditure proposal

Business Plan Area	Innovation topic	Proposed ED2 Deployment	Customer benefit
Load Related	LV Monitoring	Widespread deployment proposed for ED2 – between 17-22k deployments at a cost of up to £32m	Details in the LV Monitoring EJP
Non Load & Load	On Load Tap Changers at lower system voltages	This technology has been successfully deployed by ENWL in the Smart Street Project. The equipment dynamically manages voltage to the optimum level. Circa 130 deployments	Brings benefits to customers connected to the LV networks via reduced bills, associated losses reduction and potential headroom improvements
Load	LV Meshing	There are several options available to 'mesh' LV networks – these are solutions which can be applied in specific circumstances to provide additional LV capacity.	Additional Headroom / capacity on LV networks.

Conventional solutions

An important principle of Cost Benefit Analysis is that all credible options are compared. Conventional solutions also provide multiple potential ways of addressing network constraints, in line with historical network planning activities. Alternative approaches may consider replacement with a higher rated asset, or adding new assets alongside existing ones, different configurations at substations. In each case in our IDPs, all credible conventional options have been fully considered in the optioneering process.

Planning for Net Zero – sizing conventional network capacity

For the conventional solution options, we have identified, a critical consideration is the correct sizing of any replacements or additions; this additional capacity creates the headroom needed for future demand growth. In undertaking this capacity sizing exercise, and determining the appropriate capacity to install, we have taken full account of the range of credible post 2030 net zero pathways.

For Primary (EHV) system assets, the correct capacity to install has been considered on a case-by-case basis, taking full account of post ED2 load projections.

For Secondary transformers (11kV/LV), a standard approach is applied, again based on post ED2 load projections. The replacement asset rating has been based on aiming for the utilisation of the new asset to be no more than 60% loaded (with respect to nameplate capacity) under peak conditions at the end of ED2. Analysis of the CT scenario in 2050 has shown that in many cases this approach will ensure that the asset is adequate for our baseline view of the network requirement at 2050. This minimises the probability of the need for further work to upgrade the asset to enable Net Zero.

In some cases, we may need an alternative solution type – for instance moving from an HV/LV pole-mounted to a ground-mounted substation; in this case because a pole-mounted substation solution has a maximum practical capacity. Where a single ground-mounted substation solution can no longer provide increased capacity required then increased levels of circuit interconnection, or an additional ground-mounted substation, may be required.

Changes to the solution type normally has significant cost implications, so to mitigate this, if the largest capacity solution of the same type would still provide sufficient capacity (i.e. would be less than 100% loaded) in 2050, we have accepted with as a replacement solution even if the projected load at the end of ED2 breaches the 60% maximum rule.

If the new asset would not be able to sustain 2050 flows, then the proposed solution is to deploy LV measurement and flexibility solutions to ensure we do not unnecessarily incur the significant expense of changing solution type.

For HV and LV feeders, we take the simpler approach of selecting the maximum size cable or OHL conductor that does not incur significant additional expense- for instance, OHL routes may be strung with a thicker diameter conductor, but at a particular threshold of conductor size work would be required on the towers, significantly changing the economics of the approach. This is a low-cost method of maximizing our network headroom to ensure Net Zero readiness. We have assumed maximum-sized cable with be used to replace all first sections out from distribution substations (11kV/LV) – this includes from pole-mounted substations where the LV overhead line is overloaded.

Options already considered for other drivers

The options generated have been tested against the planned non-load interventions from other parts of our plan. For example, the same asset requiring intervention to provide additional capacity may also have been identified for intervention due to its condition, or due to environmental factors such as associated SF_6. To ensure no double-counting, work has been undertaken to ensure that interventions having different key drivers have only been captured once in the expenditure portfolio and the business plan data tables.

Summary of prevalence of considered options in EJPs

Table 21 summarises how often each solution type feature in the underlying analysis. Flexibility has been actively considered as a solution in the majority of cases. It should be noted that whilst flexibility is a valid option for addressing thermal constraints, it is usually not a viable technical nor economic option for resolving fault level constraints.

Table 21 shows that asset replacement is the dominant solution, as the simplest solution which can apply to most requirements; however, the cheaper network reconfiguration option was considered in a large number of cases, particularly for fault level at substations where busbar splitting can be an economic solution. In many cases, however, the forecast increase in demand requires the installation of additional assets to provide sufficient network capacity and to ensure compliance with network security planning standards (P2).

Innovative solutions include dynamic rating of assets, application of fault level reactors, network meshing and the considered application of on-load tap changers (OLTC) at the lower voltage levels (see Table 20)

Table 21 – Prevalence of solution types.

Solution type	Share of EJPs actively considered in
Replacement of assets	87%
Flexibility	100%
Network reconfiguration	56%
Addition of assets	27%
Innovative solutions	25%

Low Voltage Service Upgrades to Support LCT

Supporting the transition to net-zero and ensuring that we are never a barrier to the uptake of LCT means that we need to not only need to respond to network capacity needs identified through customer connection applications, but also work to pro-activity remove any network constraints or capacity 'bottle-necks' that may otherwise prevent the connection of EVs and heat-pumps. This pro-active work includes work to remove and upgrade looped services – which we consider to be the biggest barrier to customer adoption of LCT in terms of the potential delay in connection, as a result of the required remedial work.

We anticipate having to carry-out 13,000 jobs across both licence areas (3,000 SHEPD, 10,000 SEPD) in ED2 to upgrade (de-loop) looped services in response to customer LCT connection requests. This represents our reactive investment for de-looping and associated works, which includes fuse upgrades, extension asset works and broader reinforcement work. Our LV service upgrade strategy is based on the premise that any broader additional reinforcement costs associated with customers wanting to connect EV chargers and heat pumps should be shared amongst all our customers.

Our proactive investment for these works is based on the aim of ensuring that customers who want to connect an EV or heat pump have an 'LCT-ready' network available to them. Our proposal is based on identifying and targeting LV services that need upgrading and to undertake the required work ahead of individual customer need. For example, where a single customer connection enquiry or notification leads to service upgrade, this may signal the opportunity for efficient upgrade to multiple LV services in the same street or village in preparation for other new EV connections in the same locality.

This approach will allow us to establish dedicated teams and to build a programme of upgrades with the same number of jobs per week made up of both reactive and proactive jobs, ensuring a predictable workload over the ED2 period, thereby enabling unit cost delivery efficiencies and fulfilling customer needs and expectations.

Based on our estimate of average costs, this will require an expenditure of [redacted] across SSEN in ED2 for proactive replacement works, with a total of 625 jobs for SHEPD at a cost of [redacted] and 2,000 jobs for SEPD at a total cost of [redacted]. These costs as included in our CV2 table.

Our prioritisation of location for proactive investment will continually improve through advancements being made in our internal data & analytics capability relating to LCT uptake and asset constraints, along with innovation projects being delivered in ED2, such as Skyline[25].

[25] The Skyline project seeks to establish data-sharing agreements with organisations involved in the sale and lease of EVs and HPs such that customer information (GDPR compliant) is shared with SSEN at the time queries and made and orders raised. This allows assessment of properties and networks to be carried out proactively before the LCTs are due to be installed, thereby supporting planning of the proactive LV service upgrade work.

5.4 OPTIONEERING FOR AN EFFICIENT PLAN

In the previous sections, we set out how we have identified the load-related requirements of our network against a range of potential futures, and our approach to generating multiple potential solutions. The next step is the selection of a combination of solutions to deliver an overall package of interventions. This selection must meet criteria from our licence conditions, and industry regulations, and also satisfy the needs and priorities we have co-created with our stakeholders. In developing solution options, we consider the following:

- compliance with all relevant technical rules associated with our licence and other established and mandated industry standards
- selection of a solution option that deliver the outcomes stakeholders want for a reasonable cost; must be economic and efficient
- consider flexibility first wherever practicable
- stakeholder outcomes must be carefully assessed, quantified and compared to enable demonstration of trade-offs between different intervention options

This section outlines how we have analysed the options to meet the above criteria.

5.5 SCOPE OF ASSESSMENTS

For all schemes of more than £2m in value, a CBA has been undertaken alongside an EJP. The project cost threshold uses for determining the need for a CBA has been set according to Ofgem guidance and aims to manage the volume of analysis conducted and reviewed, whilst ensuring that all impactful decision points are treated in the most rigorous way possible.

Due to the high-volume nature of HV and LV networks, the constrained assets have been grouped into three types: HV feeders, secondary transformers (HV/LV) and LV feeders. A single EJP has been produced for each of these generic scheme types for the purpose of the business plan. The design and delivery of these reinforcements considers the non-load related investment portfolio to optimise efficiencies and reduce customer outages.

CBAs are a key tool for building efficiency into our plan; they demonstrate that multiple options have been considered, and that the selected option delivers maximum value for consumers. Our CBA uses the standard template and guidance for RIIO ED2 as published by Ofgem; this tool monetizes relevant benefits, nets them against investment costs, and appropriately amortizes and discounts the cost and benefit streams to arrive at a Net Present Value (NPV) of each solution.

The highest NPV solution will normally be selected; however, if multiple options are very close in value, and there is an engineering reason to deviate from the optimal NPV which is not readily captured by the CBA approach, another option may be selected. Where this has occurred, the justification is detailed in the relevant EJP.

The inclusion of flexibility solutions as an option to meet many of our requirements has necessitated the introduction of an additional appraisal tool: the ENA Common Evaluation Methodology (CEM). This CEM tool enables like-for-like comparison of between the optimal conventional (constructed) solution with a flexibility solution – such as contracting with third parties to alleviate local network constraints and hence defer investment.

The tools we use

For the purpose of investment justification, two standard industry tools have been used to ensure a consistent approach and alignment of our submission with other DNOs. The use of standard tools also provides confidence that the underlying economic assumptions are reasonable and robust.

We use two models when assessing use of flexibility in our plan. We firstly assess all conventional (constructed) solutions using the standard ED2 CBA template. The most economic conventional solution is identified and then compared to a flexibility option using the CEM model, which is used to capture and assess the potential value generated from flexibility. This process is shown in Figure 19.

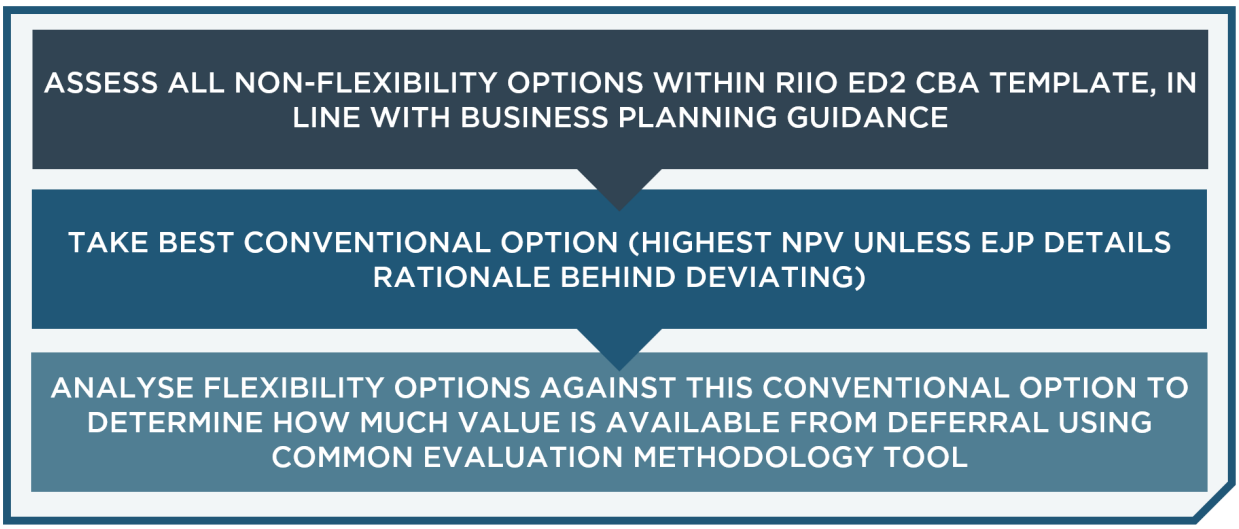

Figure 18- Hybrid CBA-CEM approach to compare flexibility to conventional solutions

The Ofgem CBA model and CEM tool

In developing our load-related expenditure proposal we have used the CBA model published by Ofgem. Supporting documentation that defines how the model should be used, is also published.[26]. We have supported industry development of the final model and guidance and have followed this in the CBA required for our load-related business plan.

The CEM tool is a standard approach to making decisions about the use of flexibility to defer capital expenditure[27]. Full guidance on the tool and how it calculates benefits is available at the ENA website[28].

26 https://www.ofgem.gov.uk/system/files/docs/2021/04/riio-ed2_cba_guidance.pdf
27 The development of the CEM was led by the Energy Networks Association (ENA).
28 https://www.energynetworks.org/assets/images/Resource%20library/ON20-WS1A-P1%20Common%20Evaluation%20Methodology-PUBLISHED.23.12.20.pdf

Side bar 7: Scope of the Common Evaluation Methodology (CEM)

A common methodology for DNOs to assess flexible vs non-flexible options to meet network needs

- Created primarily to evaluate deferral of conventional (constructed) reinforcement by purchasing flexibility. The tool can be used to evaluate a range of non-flexible options, energy efficiency and Active Network Management solutions
- The CEM Tool is a Microsoft Excel model based upon the Ofgem ED1 CBA
- DNOs use the tool to evaluate the costs and benefits of the selected options

Key drivers of CBA selections, and key output impacts

In this section some of the results from our CBAs are discussed, followed by an assessment of the net impact of our selections on the critical, non-monetised metrics of utilisation and LI index.

Across all ED2 investments, the key metrics within the CBA are consistent, aligning with the official ED2 CBA template. For Load-related CBAs, the impact on customer minutes lost (CML), customer interruptions (CI), and avoided costs have been the most relevant in identifying the option that delivers the most value for consumers.

Alongside these metrics, other key indicators include the monetised risk impact (where older assets replaced for load purposes can represent risk removed from the network) and the capacity released by our interventions. To avoid double-counting of benefits, we have ensured that these do not contribute to the NPV within the CBA template, although provides insight into the performance of the overall portfolio.

Both in terms of cost saving and network reliability, our analysis has shown interventions have long-lasting benefit. Our proposals help reduce related costs and also have a positive impact on CI and CML by reducing the overloading of network assets. Use of the CBA tool demonstrates the economic selection of solutions. And our optioneering process ensures all considered options are compliant with relevant codes and licence conditions.

Using the CBA tool, we have been able to undertake sensitivity testing on the timing of costs and benefits. We have found that NPV generally improves when projects are delayed (i.e. benefit of delaying cost is generally greater than the time value of accessing benefits sooner). This insight was coupled with the flexibility assessments to help determine our final phased investment profiles.

It is important to note that our CBAs do not capture all benefits. For example, if without intervention the network would be non-compliant, we do not consider not intervening and allowing non-compliances. We also do not attempt to monetize the benefit of being compliant, which does not affect the CBA as all options considered achieve this critical purpose.

Network utilisation analysis: current Load Indices and future forecasts

Network utilisation is an important way of understanding how our network is performing for consumers. It is a measure of peak loading on assets. Low levels of network utilisation might suggest that the network can be used more efficiently, whereas high levels of network utilisation – even going beyond the nameplate rating – can indicate that the network not be able to meet demand, with overloads potentially causing faults, leading to poor levels of reliability.

Network utilisation, as a single metric, needs to be interpreted carefully in the context of distribution system planning and network design. Constraints on networks can be driven by other factors like fault level and voltage issues that mean circuits and substations may require additional capacity to remain compliant.

Additionally, the 'lumpy' nature of network investment and the uncertainty associated with LCT uptake may mean that it is prudent to add additional capacity earlier.

At the Primary network level, we have an established approach for determining and reporting LI forecasts. At the Secondary system level, to evaluate the utilisation of distribution transformers, we have developed a sophisticated model. The load model combines supplier derived data for individual properties with network level maximum demand measurements, half-hourly metering readings and higher-voltage SCADA measurements to establish DFES projections at a local level using machine learning techniques.

There is a complicated fabric of changing demand patterns (both increases and decreases) across our grid, primary and distribution transformers. In SHEPD in 2020, 11% of our distribution transformers operated at 80% utilisation or more. By 2022, under forecast scenarios ST and CT, this increases to 18% and 20% respectively, and 24% and 34% in 2027 – without intervention.

In SSEH, 6% of distribution transformers operate at 80% utilisation or more in 2020. This increases to 7% and 8% in 2022 under ST and CT respectively, and 10% and 17% in 2027 respectively.

Near-term forecasting is more challenging than forecasting over the mid-term, given the major macro-economic effects of recent times (including COVID-19 and Brexit). Each of the DFES scenarios clearly indicates the impact of decarbonisation throughout the ED2 period, however the precise point at which this becomes the dominant effect during the remaining years of ED1 is likely to be heavily influenced by other immediate economic and policy changes.

Moving into ED2 we expect demand to increase significantly due to the LCT uptake required to meet the UK and Scottish governments Net Zero targets. This is particularly so for our LV network. Accommodating this additional demand, along with existing baseline load, will create new challenges for ED2.

Taking a flexibility first approach will mean we can maximise existing capacity in the shorter term, where appropriate, to accommodate increases in distributed-connected generation at the lower voltages, and significant increases in low-voltage connected EVs and heat pumps. However, we expect there to be an increasing need for local reinforcement which is not reflected in demand measured at Grid Supply Points (GSP).

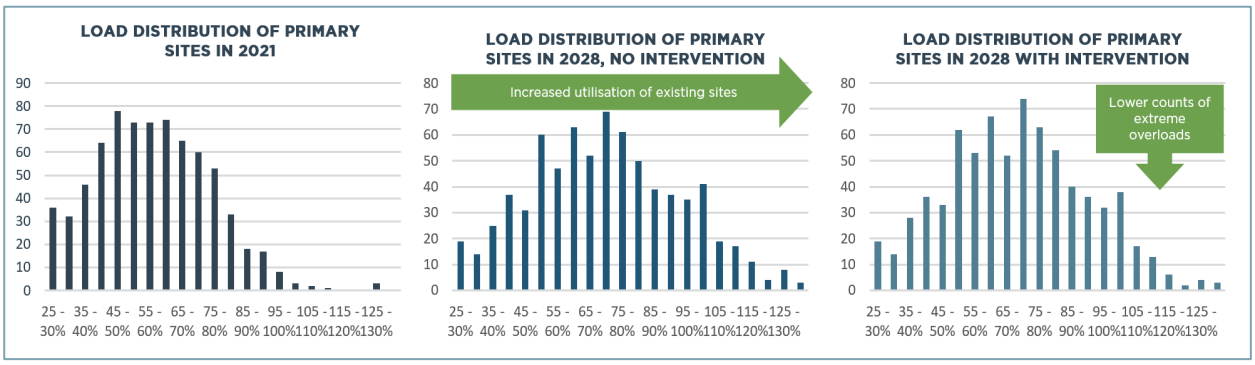

Figure 19- Load Index changes with and without ED2 intervention

Changes in load index with intervention is shown in Figure 20 and changes in utilisation are shown in Figure 21.

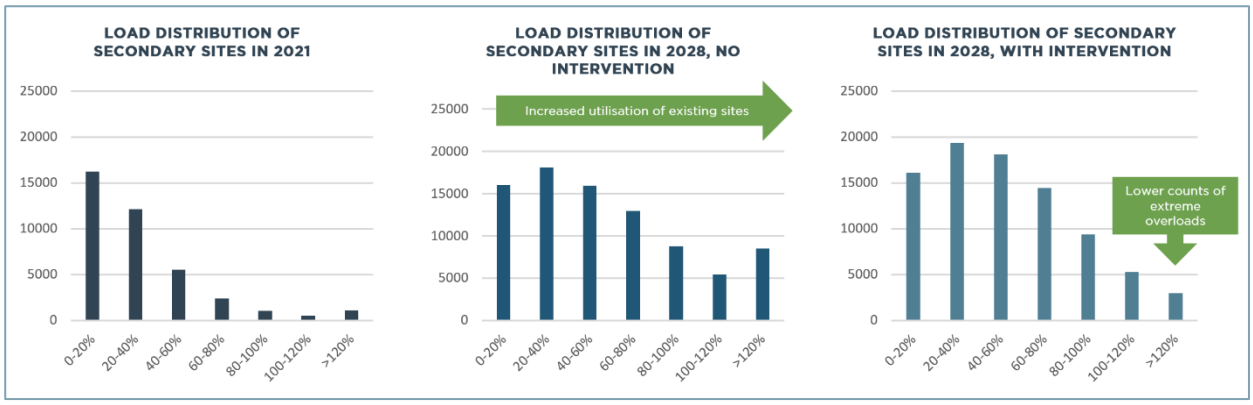

Figure 20- Utilisation changes with and without ED2 intervention

How we have applied flexibility and timing of interventions

The year that each intervention is undertaken is an important consideration. The key factors considered are as follows:

- The year the network is forecast to become constrained or non-compliant without intervention
- The resource availability to undertake the work efficiently alongside all other activities the workforce is forecast to be undertaking
- The degree of uncertainty (delaying the work may improve demand forecasts and thereby enable better expenditure decision-making)

Identifying the optimum timing for intervention work follows a simple set of rules to ensure these factors can all be addressed. This will also determine associated work volumes attributed to each year of the ED2 period. The following rules have been applied.

1. Set the latest possible date of intervention to that when the constraint arises. The CEM tool will then provide information on the value of delaying a conventional constructed intervention using flexibility services. If flexibility is economical, the CEM model will determine when the flexibility service should commence and for how long (years) the flexible service must operate until a conventional constructed (asset) solution is required.
2. Consider a smoothing of activities over the ED2 period to ensure work can be efficiently resourced. This is done at a ED2 portfolio-level and with consideration of our forecast workforce.
3. Where the opportunity exists, assess the NPV impact of delaying or advancing the work[29].

The impact of applying this process is reflected in the volumes of work shown in the submitted BPDT across the ED2 period. This is summarised in Figure 22.

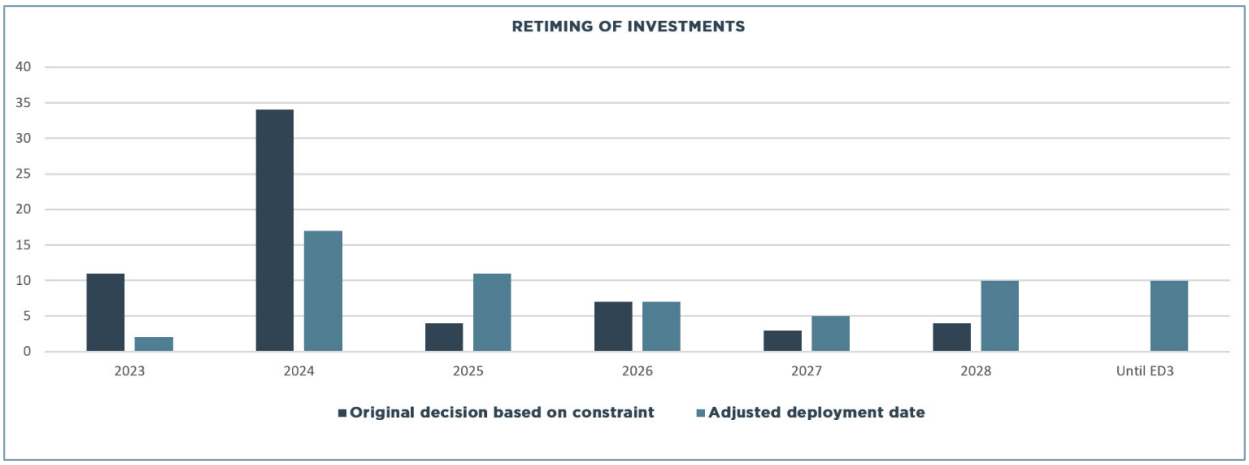

Figure 21- Impact of timing decisions

The single biggest factor in our timing of decisions is the application of flexibility for deferral. Flexibility has been selected wherever the CEM tool demonstrates a robust case for so doing in the form of a

29 In our CBAs, the NPV is improved in two schemes, Iver and Bramley, by hypothetically moving these forward- however they are already planned for the earliest credible delivery.

positive NPV assessment[30]. This price is based on our market engagement to date and reflects a central view of the cost of flexibility service. Implementation of flexibility schemes will depend on market liquidity in the right network areas to affect and mitigate a constraint.

To show a range of credible outcomes in the use of flexibility, which will vary by the cost at which it is generally accessible, a sensitivity at different assumed prices has been performed and provided in Table 24.

As can be seen in Table 22, we have found significant scope for potential savings from deploying flexibility services. More details on our approach to the use of flexibility in ED2 can be found in our ***DSO Strategy (Annex 14)***[31].

Table 22- Use of flexibility for investment deferral in our load plan

Summary- application of flexibility in Load	
CAPEX deferred to ED3	£22.3m - £49.8m
CAPEX savings in ED2[32]	£5.0m - £8.5m
Cost of procuring flexibility services	£9.3m - £8.1m
Flex Capacity considered	810MVA
Flex Capacity used	272 - 368MVA

Overall impact of optioneering

The first-pass assessment of our constraints, coupled with the application of efficient unit rates for a conventional way of resolving these constraint archetypes, generated a view of £611m of expenditure required to address all the network issues identified across both networks (excluding connections driven spend). This initial analysis was based on the CT scenario. Subsequent engineering analyses and optioneering reduced this initial cost assessment by 36%. This is shown in Figure 23.

30 Assumes flexibility can be secured at a cost of £150/MW/hour for availability and £150/MWh for utilisation.

31 A15, Appendix F.

32 Direct savings, as defined in the ENA's Common Evaluation Methodology, come from the benefit of delaying investment, hence accessing the time value of money being deferred- less the cost of procuring the flexibility.

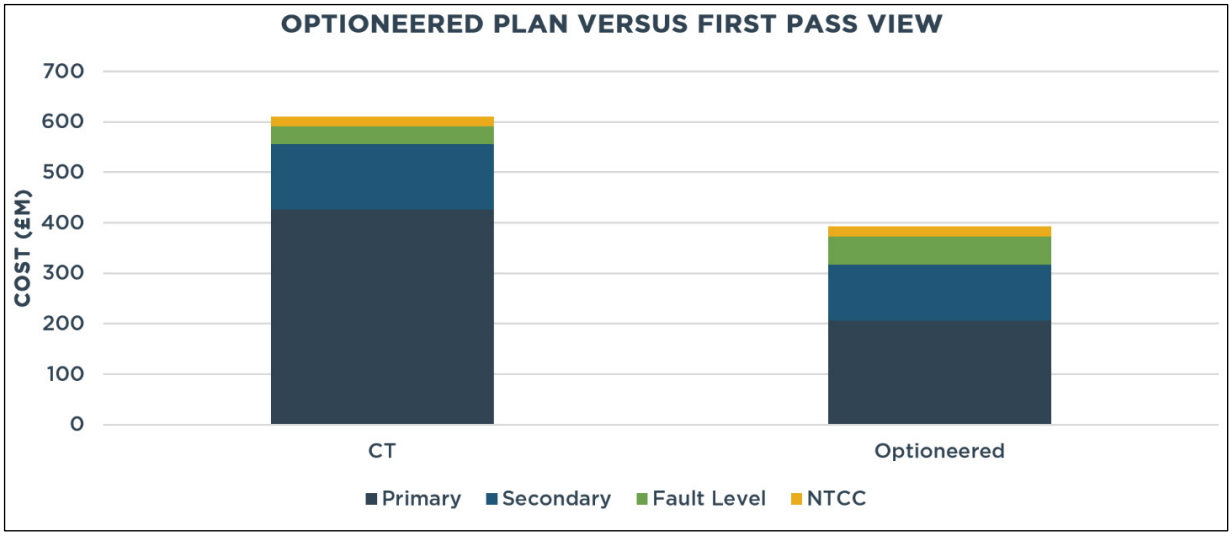

Figure 22- Monetised impact of optioneering

The three main sources of the reduction are described further below.

1. **Engineering analysis and detailed power system modelling** to refine the scope of work and optimise investment; identifying that in some cases only a subset of the affected components or lengths of circuit need intervention. In other instances, showing how attributing a dynamic rating to assets can ensure compliance without intervention.

2. Through our ongoing work to determine ambitious trajectories for **unit cost reductions** associated with intervention activities; and

3. By realising efficiencies identified through our optioneering process, and the inclusion and assessment of a wide range of solution types including **flexibility, whole system, ED1 innovations, network reconfigurations and conventional asset solutions**

Sensitivity analysis of optimal interventions

One key objective of our ED2 submission is to identify an investment strategy that is robust across different credible pathways to net zero. To ensure this is the case, we have studied network requirements across all DFES, and analysed our proposed interventions against these needs. We have categorised the relative certainty of each proposal, and the relative cost of each scenario in terms of required investment. This is shown in Figure 23.

We have also used sensitivity analysis to enhance our confidence in the robustness of the business plan. This type of analysis answers the question "what would we need to believe for the right option to pursue to be different to our baseline answer?". This question can be asked in the context of any of our input assumptions. To create a coherent and useful set of sensitivities, we have focused on assumptions we view as critical, as well as those suggested in the business plan guidance. Table 23 presents the sensitivities we have undertaken for load-related expenditure.

Table 23- Sensitivities on LRE undertaken

Name	Key parameter(s)	Description
Peak demand sensitivities (With CCC assumptions)	EV charging profiles, Heat pump usage profiles	Work to establish the plausible range of peak demands that could be experienced at LV feeder and secondary transformers. We have selected the worst and best credible cases of consumer behaviour for peak loadings on the LV network. This has enabled demonstration of how the optimum level of LV investment varies with demand profiles.
Would we make different decisions if we were making submissions for the post 2030 period?	Year studied	Our submission focuses on what we will do in the ED2 period. These decisions are made whilst considering what will happen post ED2; when intervening in our network, we factor in post 2030 network loading when sizing assets to ensure we minimize rework. We have also reviewed what we would do if we were making decisions for out to 2035 at this time; this tells us about how robust our plan is for 2023-2028, and how that set of interventions will flow into the 2030s where further requirements will arise.
Demand and anticipatory investment testing	Assumed demand	This exercise tests how much of our portfolio can be considered 'anticipatory', to understand how influential capex and demand are on our anticipatory measure.
How much flexibility is economic at different prices?	Availability and utilisation costs for deploying flexible solutions	Using the CEM template, we varied our key assumption around how much we might need to pay to secure flexibility to defer the need for asset investment.

Sensitivity 1: Peak demand variations

Forecasting of future peak demand at different points on our network has required comprehensive processing and modelling of the DFES. This process has required a number of assumptions to be made around how LCT demand might manifest at peak times and applying these assumptions to the uptake of different technologies forecast by the scenarios. These assumptions form the basis for thinking about peak demand sensitivities, as LCT peak demand behaviour in future years is subject to uncertainty due to uptake not being sufficiently widespread at present to be certain how consumers will use such technologies in future. Key examples of such assumptions and uncertainties include:

- **Smart charging of EVs:** The prevalence and consumer uptake of offerings where their charging is incentivised to occur at different times on the network, mitigating impact on peak demand. Specific offerings could even respond to specific network constraints, meaning EV flexibility could help defer network investment, rather than drive it. The extent to which these offerings are present and accepted could therefore significantly vary peak demand estimates at different points on our network.

- **Heat demand:** Whilst heating demand has lower inherent flexibility than EV demand, different levels of uptake of measures which improve the thermal efficiency of buildings, or applications of heating storage solutions could mean that installed heat pumps have different loading requirements in the future.
- **Technology clustering assumptions:** Our scenario work has included the allocation of technologies to specific points in our network, with our 'best view' of how uptake could progress geospatially; changes to the underlying assumptions could mean the impact of LCTs could appear more rapidly on single network nodes, with a higher rate of clustering, or conversely be more spread out in their initial impact meaning fewer overloads in early years of uptake.

These factors can all drive differences to the forecast peak demand at different nodes on the network, and hence increase or decrease investment needs from our base case. To gain understanding of the potential impact and ensure the envelope of uncertainty is something our base plan is robust to, we tested higher and lower peak demands commensurate with the uncertainty present in our peak demand assumptions.

Figure 24 summarises the results of this testing, with the left-hand figure demonstrating a worst-case view on a low voltage asset, and the right hand figure showing a band of changes to our secondary asset investment requirements (illustrated by our base case, CT) driven by the most extreme but credible sensitivities tested. This range of cost changes foreseen illustrate the scale of the uncertainty in our needs within ED2, however we are confident that our baseline plan, coupled with uncertainty mechanisms and monitoring of how demand is changing through ED2, will enable us to respond efficiently and effectively to the range of potential future outcomes.

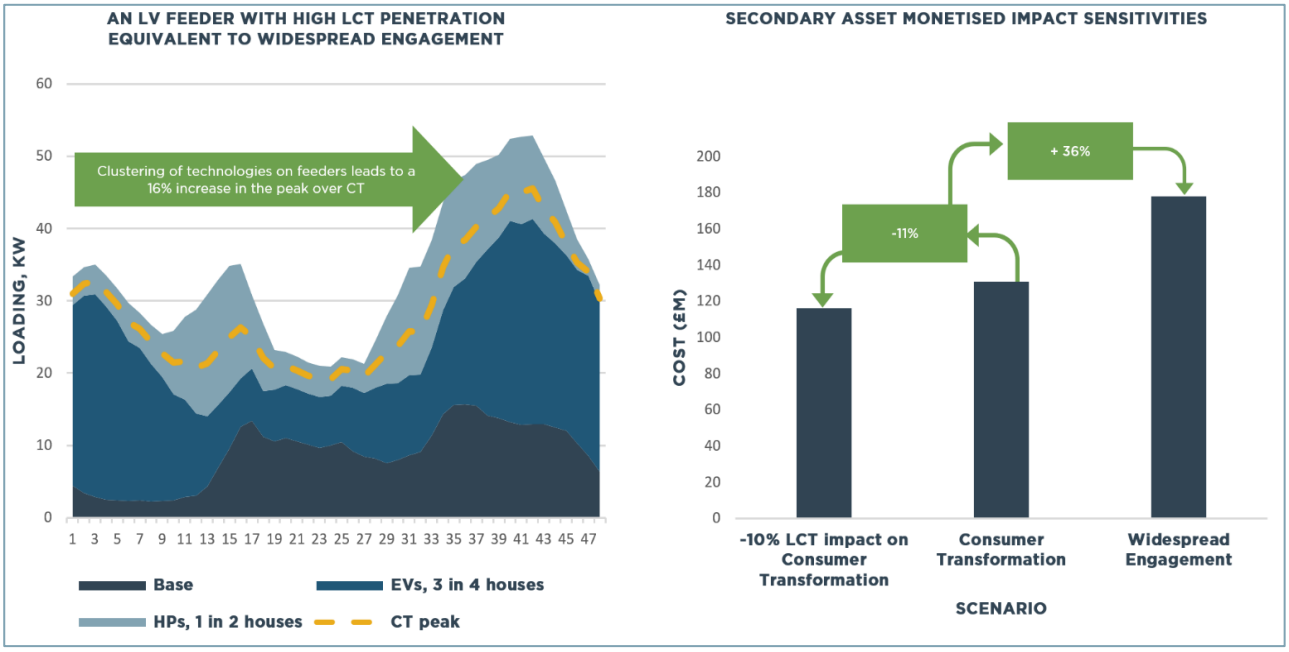

Figure 23- key results from varying LCT impact

Sensitivity 2: Post 2030 constraints

We recognise the importance of understanding network constraints post 2030 and into ED3. This sensitivity analysis has been designed and is being undertaken for inclusion in our Final Business Plan submission.

Sensitivity 3: Percentage of our load plan which could be regarded as anticipatory

A key principle of load-related investment is making timely interventions in anticipation of future growth in supply and demand connected to our network. Being based on a forecast set of assumptions our investments are not only designed to meet current network constraints but are also designed to be futureproofed to later year growth. This principle is important so that we minimize the disruption to customers wanting to connect and to society at large. As far as possible we aim to adopt a 'touch the network once' principle in developing the network to deliver net-zero. In delivering anticipatory investment however we need to be cognizant of the potential for asset stranding and ensure that we minimise this risk. Our use of flexibility is a key tool which gives us some option value before committing to costly and irreversible constructed network interventions.

As part of our decision-making, we have sought to understand how much of our load-related plan could be regarded as anticipatory in nature and how this might change with changing demand. A measure of network utilisation through the load-index on Primary network and utilisation banding on the Secondary network can provide some insight into this; but is limited in that no consideration is given of the extent to which proposed investment is directly linked to growth in peak demand in ED2, or to increases in peak demand in future years.

We have sought to go beyond this measure of utilisation in order to test the sensitivity of our overall load-related investment plan to changes in peak demand. To do this we have devised an equation for 'percentage anticipatory' which aims to provide an indication of the amount of the proposed investment which could be classified as anticipatory (i.e. not directly linked to the growth in peak demand in ED2). Importantly it allows testing of how changes in peak demand could impact the percentage of investments classed as anticipatory in the ex-ante baseline – all else being equal.

$$\%\text{Anticipatory}_{\text{ED2}} = \frac{\sum_{\text{ED2}} \text{CapEx (Load)} \times \left(1 - \frac{\text{Peak demand}_{2028} - \text{Peak demand}_{2023}}{\sum_{\text{ED2}} \text{Capacity released}}\right)}{\sum_{\text{ED2}} \text{CapEx (Load)}}$$

Applying the above equation to our ED2 ex-ante baseline plan and testing sensitivities of peak demand for our licence area we observe the results in Figure 25. This highlights that the percentage of investment which could be classed as anticipatory in ED2 is linked to the growth in peak demand with the period. The CT scenario, our ex-ante baseline scenario for the first two years of the period, has the highest growth in peak demand and so the lowest volume of investments which are not classed as anticipatory. The Steady Progression scenario whilst having the highest absolute demand at the start of ED2 has a low growth rate in peak through the period, which means that should this scenario outturn then more of our investments could be classed as anticipatory in the ED2 period – relative to CT.

It is important to note however that these investments would not be stranded given the higher growth rates for the Steady Progression scenario post-ED2, as shown in the right-hand plot in Figure 25. This is equally true for the System Transformation Scenario. Leading the Way has a lower percentage anticipatory compared to System Transformation and Steady Progression owning to a slightly steeper change in peak demand growth, though not as steep as the Consumer Transformation. We observe higher percentages of anticipatory investment in the South versus North on account of the higher absolute spend in the denominator of the above equation relative to a lower difference in the peak delta over capacity release between North and South.

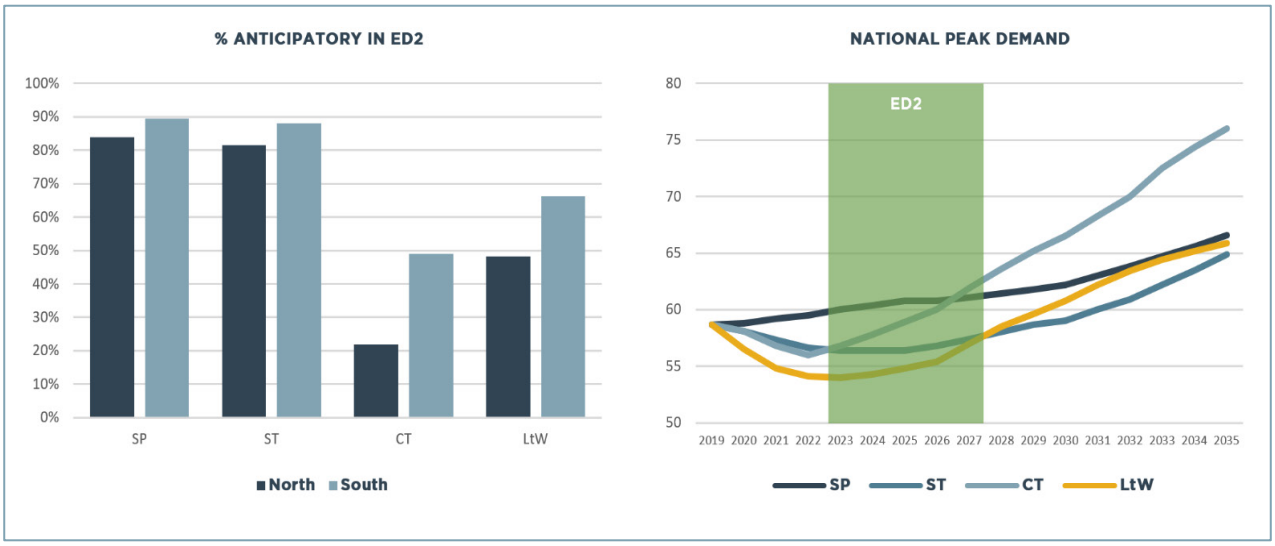

Figure 24: Percentage anticipatory investment sensitivity analysis

Sensitivity 4: Flexibility cost

The widespread usage of flexibility during ED2 is a core priority in our plan, and section 4 of the main report articulates our overall strategy, plans and benefit appraisal for DSO and flexibility as a whole. Within our load related EHV investment, we have identified many schemes where there is a clear economic case for deferral through flexibility, at our central price assumptions of £150/MWh for availability and utilisation.

We have replicated our assessment process with two further price assumptions, halving and doubling the price to create a credible range. The results, shown in Table 24, show that decreasing the price can increase usage of flexibility to over two thirds of the total capex considered. Doubling of the price only results in a 14% reduction in deployment (in capex terms). This demonstrates that the case for flexibility is extremely robust for 173 MVA of projects and could be made for up to 270MVA at ambitious but credible flexibility prices. More details on potential price sensitivities for LV and HV flexibility can be found in Appendix F of our ***DSO Strategy (Annex 14)***[33].

Table 24- Flexibility Price sensitivities at EHV

	£75 flex price	£150 flex price	£300 flex price
CAPEX Deferred to ED3	£41m	£17m	£13m
CAPEX Savings in ED2	£8m	£6m	£4m
Flex Costs	£5m	£3m	£3m
Flex Capacity considered MVA		710 MVA	
Flex Capacity used MVA	270 MVA	220 MVA	173 MVA

5.6 EFFICIENTLY FUNDING THE PLAN

In this section we provide a synthesis of our ex-ante baseline plan and potential expenditure subject to uncertainty mechanism. This is mapped to regulatory requirements and outputs; including expectations set out by Ofgem on spend categorization. In Section 7 we provide more detail on how we propose dealing with future uncertainty.

Through our engagement with Ofgem it has been set out as a requirement that DNOs should articulate proposed expenditure in three categories to aid with understanding the nature of the anticipated expenditure and the proposal for efficient funding. These three categories are as follows.

1. Business-as-usual (Category 1)
2. Future proofing to ensure no future pathway is foreclosed (Category 2); and
3. Required only if underlying assumptions materialise (Category 3)

Category 1 provides for 'business-as-usual' – where we have high certainty of need and there is little sensitivity to the range of forecast assumptions. Category 2 represents the additional baseline expenditure required to ensure that future pathways are not foreclosed – 'futureproofing' to ensure that

[33] A14, Appendix F.

the foundations are in place to enable demand increase which occurs post-ED2 to be met efficiently. And Category 3 is the expenditure which likely to be needed, but only if specific forecast assumptions materialise, noting that the emergence of different assumptions may change the total level of spend in this category.

In the ED2 period we propose to spend £393m through our baseline load plan. In total however our expenditure requirements could reach £600m in the ED2 period. This excludes connection-related reinforcement.

Business-as-usual load-related expenditure (Category 1)

Our approach to determining the 'business-as-usual' category of load-related expenditure is to base our proposed expenditure on the project and schemes which appear in all three of the net-zero (DFES) future pathways. This is our test for high certainty of need. All of our proposed investments which appear in the System Transformation (ST) scenario, also appear in Consumer Transformation (CT) scenario and also in Leading the Way (LW). Our BAU expenditure is therefore based on DFES ST scenario. This represents £352.5m which is approximately 90% of our anticipated funding in ED2.

Futureproofing to build foundations and keep open future credible pathways (Category 2)

The second category of expenditure is that which we believe is needed to ensure that future options remain open – that is, the additional expenditure needed to ensure that we have the essential foundations in place to meet the potential demands of the future in a way that avoids inefficiency, duplication and unnecessary cost and inconvenience to customers and communities. Our proposal for this is that in years 1 and 2 of the ED2 period we commit the expenditure based on our view of CT – the scenario we have selected as the 'baseline' future pathway for ED2.

This additional expenditure – over and above ST – associated with delivering our investment in accordance with CT in this first two years of the period is £39.9m and will ensure the early and timely establishment of the capacity (supply chain, people and network) and ability required to deliver to CT throughout ED2 – should our anticipated baseline scenario come to pass. Failure to provide this level of capacity preparedness will mean higher costs and inefficiencies for customers in the longer term as the investment required to support net-zero moves from being anticipatory and strategic in nature, to reactive and short-term focused.

Why are we only requesting two years of ex-ante baseline funding for Consumer Transformation?

The ability and confidence to being able to deliver the investment plan is critically important. We will enhance our capacity to execute and mobilise (people, workforce, systems and supply chain) in the first two years of ED2. Our ability to ramp-up our load-related delivery capability in the first two years of ED2 will act as a measure of our commitment and endeavour to ensure that future (prudent and efficient) pathways to net-zero remain intact.

Two years is the typical lead time required to plan, design, construct and commission our larger substation and circuit investments. We need to remove uncertainty and make decisions in the remainder of ED1 if we are to mobilise and execute network investment plans. Also, major customer connections

application enquiries are often 'live' up to 2 years ahead of need. A time period less than 2 years is likely to be insufficient to plan and prepare for efficient and timely delivery of the required capacity.

In the best case, a short-term, reactive approach to development of the network will burden customers with unnecessary costs and inefficiencies. In the worst case, failing to prepare whilst waiting for a high degree of certainty of the investment 'need' risks failure to provide sufficient capacity at the right place, and at the right time. This would lead directly to customer and societal costs (e.g. customers have to wait for the local infrastructure before they can buy an EV) and the associated risk of failure to meet Government's net-zero targets.

Conversely, we believe that committing to expenditure now for potential capacity needs beyond the first two years of ED2 is unnecessary and runs a higher risk of our customers having to pay higher costs than needed. We will maintain the 2-years planning time window as we move forward – drawing on uncertainty mechanisms to fund prudent and efficient load-related expenditure as we move through the ED2 period and beyond.

This is a key part of our strategy to ensure that no future pathway is foreclosed. Keeping open options for customers and being ready to mobilise and deliver according to the alternative scenarios should the assumption materialise.

Some of our expenditure in ED2 is uncertain and will depend upon specific assumptions materialising

Finally, the third category of expenditure is that associated with CT beyond the second year of ED2. Whilst we believe that this represents a credible forward baseline scenario to the end of ED2 and beyond, we accept that this relies on specific assumptions materialising and therefore presents an intrinsic level of uncertainty. For this reason, we propose that this expenditure category is funded through uncertainty mechanisms whose triggers are clearly defined. Work continues by DNOs and Ofgem to define these. This category of expenditure is estimated to be £211m. Figure 26 shows disaggregation of the load-related reinforcement into the three categories which Ofgem has asked network companies to consider.

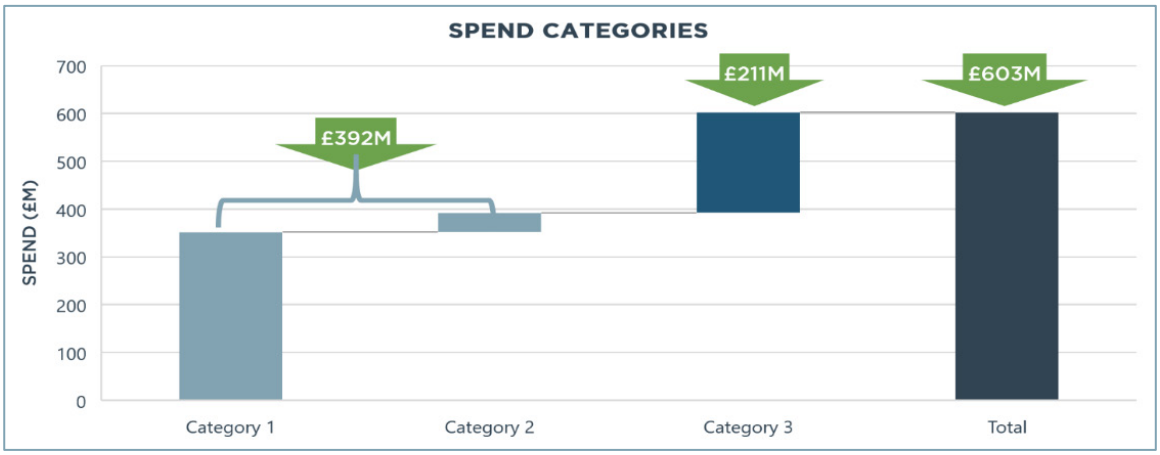

Figure 25: Total quantum of ED2 load related spend distributed by group (excludes connections-related reinforcement)

In summary we be believe the CT scenario provides a credible forward projection for ED2, particularly given the strong evidence of support from our stakeholders. However, we feel that in terms of efficient funding, our ex-ante baseline allowance should provide for the minimum required investment required under all scenarios – as determined by the ST scenario (Category 1), plus the amount required to ensure that no future pathway is foreclosed. We have achieved this by including in the ex-ante funding proposal the additional efficient expenditure required for CT scenario in the first two years of the ED2 period (Category 2). Adjustment to the baseline funding – including any additional funding required over-and-above that for ST in years 3 to 5 of the period, will be provided via the uncertainty mechanism. We would still anticipate an appropriate uncertainty mechanism operating for the full 5-year period.

Our ex-ante baseline allowance proposal is therefore approximately 65% of our total expenditure which we anticipate requiring in ED2.

6. A CREDIBLE TRANSITION FROM ED1 TO ED2

Since the start of RIIO-ED1, we have released over 650 MVA of capacity on our network (primary reinforcement) and connected over 2,750 MW of low carbon technologies to our network. Through the introduction of innovative solutions such as flexibility and Active Network Management (ANM) we have connected customers to our network more efficiently, delivering significant savings, and paving the way for the roll-out of innovation into business as usual in RIIO-ED2.

Overall, in both licence areas, network demand did not increase as anticipated at the start of RIIO-ED1. This was primarily the result of slower recovery from economic downturn. A number of customer-driven schemes were also cancelled, and several large connections e.g. data centres in the SEPD network area have had a particular impact. However, targeted reinforcement has still been required at the local level to deal with constraints and to provide firm capacity. We have also experienced pockets of rising demand across both licence areas. Overall, downward pressures have been slightly offset by the level of distributed generator connections in SEPD and SHEPD, driving an increase in the associated apportionment reinforcement works.

Our RIIO-ED1 forecast was based on an assessment of likely economic uptake and assumption that tariffs to incentivise uptake would continue to encourage significant uptake of LCT. There will have been delays in uptake compared to RIIO-ED1 expectations resulting from a combination of factors such as economic growth and technology availability, and the wider context has changed significantly since our RIIO-ED1 forecasts were produced.

We are now seeing increases in customers seeking to connect to our network in the latter years of RIIO-ED1, with the trend expected to continue into RIIO-ED2, in particular as a result of the expected increases in EVs and heat pumps. We also anticipate that the number of embedded renewables will progressively increase in the latter years of RIIO-ED1 and into the RIIO-ED2 period. Enabling the connection of increased levels of generation, in particular in the North, will help create a solid foundation to support governments' Net Zero ambitions.

EV chargers

There are over 40,000 EV chargers in total installed in our licence areas. This compares to a forecast of 42,600 EV chargers (28,000 fast chargers) by 2019/20 in our RIIO-ED1 Business Plan. We have seen a 65% increase in EV connection notifications/applications across SSEN from 2019/20 to 2020/21 (62% increase in SEPD, 59% increase in SHEPD).

We do not have visibility of all EV chargers connecting to our network, as installers do not always notify us. Since the start of RIIO-ED1, we have had formal notifications for over 7,000 EV fast chargers (170MW). We are seeing a steep increase in the number of installation notifications across both our licence areas, with a 40% increase in our SHEPD network and 151% increase in our SSES network in 2019/2020 comparison to 2018/19.

We expect to see this trend continue for the remainder of RIIO-ED1 and into RIIO-ED2. Based on our current DFES projections[34], and using Consumer Transformation, we expect to see around 1,660MW of EV

[34] Source: https://www.ssen.co.uk/SmarterElectricity/

chargers connect to our network by the end of RIIO-ED1, rising to around 6,000MW by the end of RIIO-ED2.

EVs

We did not provide a specific forecast for EVs in our RIIO-ED1 Business Plan. According to government data, at the end of 2020 there were over 120,000 plug-in hybrid and fully electric vehicles registered in our licence areas[35]. This includes cars, buses and coaches, LGVs, and HGVs.

We expect to see significant increases in EVs over the remainder of RIIO-ED1 and into RIIO-ED2. Based on our current DFES projections and using Consumer Transformation, we expect to see over 245,000 EVs in our network areas by the start of RIIO-ED2, rising to 1.3m by the end of the period.

Heat pumps

According to government data there are over 20,000 heat pumps in total installed in our licence areas[36]. We do not have full visibility of all heat pumps connecting to our network, as some are 'behind the meter' and we are not always notified of their installation. In 2019/20, we received formal notification for over 1,461 domestic heat pumps on our network. This compares to a RIIO-ED1 forecast of just over 92,000 by 2019/20. However, as with EV chargers and EV number, we expect to see a significant increase over the remainder of RIIO-ED1 and into RIIO-ED2. Based on our current DFES projections and using Consumer Transformation, we expect to see over 208,000 heat pumps in our network areas by the start of RIIO-ED2, rising to over 700,000 by the end of the period.

Efficiencies and innovation benefits

We recognise the benefits that can be delivered by embracing flexible solutions ahead of reinforcement, where appropriate. We have achieved savings of just over £60m for customers across both our networks in RIIO-ED1 through flexible solutions in RIIO-ED1. We have introduced flexible connection solutions and Active Network Management (ANM) type innovations which help avoid investment and allow customers to connect quicker and at lower cost. This includes schemes on the Isle of Wight in SEPD and on the Western Isles in SHEPD, where we have deferred load expenditure through to the use of ANM schemes.

We provide a detailed overview of our approach to Flexibility and Whole Systems in ***DSO (Chapter 11)*** and ***Whole Systems (Chapter 12)*** of this Business Plan respectively.

35 Source: DVLA/Department for Transport Vehicle Licensing Statistics.

36 Source: Renewable Heat Incentive (RHI) data.

7. WHAT IF THE FUTURE IS NOT AS PREDICTED?

Our business plan submission is ex-ante based. We have used the DFES scenarios to inform our baseline allowance proposal. In section 5, we outline our strategy to efficiently fund our plan which is to request only the first two years of funding to deliver Consumer Transformation as the baseline scenario. We have also identified that there may be up to £211m of additional allowance needed if underlying assumptions in the DFES materialise; with this allowance funded through an uncertainty mechanism.

The assumptions underpinning the load-related baseline plan and the associated load-related expenditure are likely to change. The trajectory for net-zero, and the trajectory of the local authorities in our licence area may alter significantly during ED2. Changes in public policy of democratically elected bodies may occur; therefore, might changes in customer and stakeholder requirements; or in technology evolution; and changes in energy market development can have a significant bearing.

The four DFES 2020 scenarios attempt to capture the uncertainty faced to a reasonable extent, but they are not exhaustive. For example, the key differentiators between our baseline view and ST scenario, are that ST has:

- Substantially lower uptake of battery EVs (especially for the North licence area)
- Lower penetration of domestic and non-domestic EV chargers
- Substantially lower uptake of domestic and non-domestic heat pumps (especially relative to the Consumer Transformation trajectory used for 2023-2025)
- Substantially lower uptake of small-scale solar PV, especially at the domestic (<10kW) level

The key differentiators of Leading the Way (as compared to the baseline plan) include:

- Substantially higher uptake of battery EVs (especially for the North licence area)
- Substantially higher penetration of domestic and non-domestic EV chargers
- Substantially higher uptake of domestic and non-domestic heat pumps (especially non-hybrid heat pumps)

It is entirely possible that our upper end of additional spending required, £211m, could be exceeded by more ambitions government policy or faster changes in the market outside of the DFES scenario envelope. Equally the pace of achieving net-zero may be slowed by a variety of factors in the ED2 period and so it may become necessary to delay parts of our baseline plan until ED3 when clarity emerges.

Having an agile and adaptive regulatory framework which can adjust the level of total expenditure in ED2 to accommodate changes in external influencing factors, is vital.

In ***Uncertainty Mechanisms (Chapter 17)*** and ***Uncertainty Mechanisms (Annex 28)***, we set out our proposals for managing externally driven uncertainty in the ED2 period. This includes proposals on a range of uncertainty mechanisms which can allow allowances to adjust for specific events. Ofgem has also

set out, through its Sector Specific Methodology Decision (SSMD)[37], uncertainty mechanisms applicable to the whole distribution sector and some applicable to all RIIO-2 companies.

We have been working directly with Ofgem and other stakeholders over the course of the last 18 months to consider the need case and principles of operation for new forms of uncertainty mechanism, applicable to all DNOs. We propose that Ofgem pursues an automatic (volume driver) uncertainty mechanism for load related expenditure. We believe that an automatic mechanism is necessary so DNOs can respond quickly to the changes likely in the ED2 period, which the existing load related re-opener mechanism does not currently allow for. We believe that the uncertainty we face in ED2 is continuous in nature, rather than a discreet uncertainty. We believe that the uncertainty is likely to be characterised by continuous distributions with a very large set of possible outcomes and cost impacts (for example, uncertainty over the number of electric vehicles purchased by consumers over ED2).

Based on our DFES scenario analysis we believe this uncertainty could range from:

- South: £291m to £486m, relative to a baseline of £322m (-£31m to +£164m)
- North: £62m to £117m, relative to a baseline of £71m (-£9m to +£46m)

We have discussed at length with industry stakeholders the key considerations and principles of operation for an uncertainty mechanism in this area. Through our working group involvement over the last 18 months we have heard in detail the views of a range of stakeholders, including consumer advocate groups and academia. Furthermore, we have spoken directly to stakeholders relevant to our licence areas on the need case for an uncertainty mechanism. Our Stakeholder Advisory Panel, for example, has recognised the need for this UM across the sector, noting that the degree of use will vary across DNOs due to regional variations in LCT uptake and broader Net Zero transition.

Additionally, our broader stakeholder community has told us that they support the mechanism, and additionally the need for significant anticipatory investment, but expressed concern that a capacity-based volume driver could lead to excess customer bill volatility if not designed carefully, given the significant investment required. We have taken this into account while continuing the iterative design process with Ofgem in the working group.

We continue to work closely with Ofgem and other DNOs on plans for a utilisation incentive, which will counterbalance the volume driver by strongly disincentivising excess investment (thereby reducing the likelihood of significant upward bill volatility). We have also ensured that stakeholder views on the importance of anticipatory investment are accounted for in our ED2 baseline plan.

The detailed design of a volume driver is currently being worked upon through cross-industry cooperation and we aim to be able to propose a detailed mechanism in our final ED2 business plan, pending successful completion of working group outcomes and indications of Ofgem support by early autumn. Our ***Uncertainty Mechanism (Annex 28)*** contains a comprehensive layout of our proposals at this stage in the submission process.

We recognise the breadth and magnitude of load-related investment at ED2, and that it may be necessary to adopt a combination of volume-driver mechanisms (each with tailored UCA designs and calibrations),

[37] https://www.ofgem.gov.uk/system/files/docs/2020/12/ed2_ssmd_overview.pdf

rather than adopting a one-size-fits-all approach with a single volume driver. This approach would have the benefit of aligning allowance adjustments closely to the precise activities delivered, minimising the extent to which there are windfall gains or losses should the unit costs of additional investment vary significantly across different reinforcement project types.

The proposed volume driver will allow for the triggering of higher or lower allowances in response to the load on our network, which will be strongly influenced by how the development and uptake of LCTs progresses over ED2. As ED2 evolves we will monitor the path of LCT uptake, assessing how this compares against our scenario projections and using this to revise our investment plans accordingly. Should LCT uptake exceed the forecasts used for our baseline ED2 plan, this will indicate a strong needs case for additional load related investment to meet rising demand. We propose these assessments should be made annually to assess the need to trigger the volume driver.

However, it is important to distinguish the aforementioned indicators of network load from the formal triggers used to operate a load related volume driver, although these are closely related, and we consider that LCT uptake should have a strong influence in determining the need for (and approval of) additional investment. More generally, the volume driver needs to be accompanied by a clear trigger which is consistent across all DNOs and externally transparent. We are open to further discussions with Ofgem and other DNOs on an appropriate sector-wide form and process for this trigger.

We recognise that there needs to be transparency over DNOs' load-related investment decisions, to provide the required assurance that any additional investment undertaken is necessary and efficient. We consider that the volume driver needs to be accompanied by a clear trigger which is consistent across all DNOs and externally transparent. We are open to further discussions with Ofgem and other DNOs on an appropriate sector-wide form and process for this trigger.

Appendix A MINIMUM REQUIREMENTS

Table 25 provides details of the relevant minimum requirements and where we have described how we address these within this document.

Table 25 – Mapping of Ofgem Minimum Requirements

	Min req.	Where and how addressed in narrative
5.1	N/A	N/A
5.2	N/A	N/A
5.3	DNOs must demonstrate that their forecasts have been informed by the range of assumptions found in the Net Zero compliant energy pathways in the Electricity System Operator's 2020 FES, and the Climate Change Committee's 6th Carbon Budget.	**Section 5.2** addresses how we develop our forecasts, and our sensitivities in **section 5.4** discusses variation of some of these assumptions.
5.4	DNOs must use these key assumptions as part of determining the range of demand for their network.	**Section 5.2** demonstrate**s** how our scenarios are adapted into potential network demands
5.5	We also expect DNOs to assess the need for investment beyond 2030 that may be required in order to deliver against Net Zero targets… We expect DNOs to take into account the degree of divergence between pathways when identifying both the potential need for investment and the certainty they have on the investment being required under a range of future scenarios.	**Section 5.3** discusses how we assessed network requirements across all DFES, and our thinking for how this divergence can be accounted for through plan funding is outlined in s**ection 5.5**.
5.6	In establishing these scenarios, DNOs should engage with local stakeholders to understand what trajectory for decarbonisation is likely to be followed in that licence area. As a minimum requirement under Stage 1 of the BPI, DNO Business Plans should set out a detailed description of the process through which this engagement has been conducted.	**Section 5.2** outlines how we co-created the scenarios with local stakeholders
5.7	the licensees should include evidence of: --- relevant network planning data being made available to external stakeholders in a digitised and open form. --- the manner in which the data from this modelling was made available to other stakeholders	**Section 5.3** covers how we reach out to stakeholders to share where we require flexibility options. Details of our planning scenarios as outlined in **section 5.2** are also made available.
5.8	DNOs will need to transparently set out how they have translated forecasts on	This is explained in detail in **section 5.2**

	Min req.	Where and how addressed in narrative
	overall demand into an increase in demand at peak times.	
5.9	We also expect DNOs to undertake a sensitivity analysis around this to demonstrate how changes in these assumptions could impact on the level of peak demand, and any associated investment requirements.	This and other sensitivity types are discussed in **section 5.4**
5.10	In developing scenarios the licensees should include evidence of how this process took account of the alignment between regional and national targets and the reasons for any differences.	This is discussed in **section 5.2** under its own heading
5.11	There are several methods that a DNO could use to establish a forecast of demand expected for its areas	Our method described in **section 5.2.**
5.12	In any case, the DNOs should detail the nature of the modelling that was conducted to establish a regional forecast to Net Zero in their Business Plan.	Detailed in **section 5.2**
5.13	we require more than an investment plan based around single set of assumptions that a DNO views as most likely to arise.	How we make our decisions, and how our investment may vary based on more than one view, is outlined across **sections 5.3 5.4 and 5.5**
5.14	DNOs must show how they evaluated the investment required under each possible future pathway/scenario that we have identified above. DNOs must use this analysis to distinguish between investment that is reasonably certain to be required across different pathways, from that which may only be required under a specific set of circumstances, even if these represent a DNO's most likely view of future demand.	Variation in investments required across different scenarios are discussed in **section 5.3**
5.15	They should seek to identify an investment strategy that is robust across pathways/scenarios, i.e. which performs well (is close to optimal) no matter which pathway/scenario occurs	The logic behind how our investments could vary, and therefore the split between uncertain and certain costs, is covered in **section 5.5.**
5.16	Careful consideration should be given to the timing of investment decisions.	Our approach to the timing of investments is explained in **section 5.4**
5.17	We expect the use of flexibility to be fully considered by DNOs and clearly outlined as part of the analysis presented in business plans and we anticipate it will form a key part of expenditure funded through baseline allowances.	Our consideration of flexibility is explained in **section 5.4**

	Min req.	Where and how addressed in narrative
5.18	We expect DNOs to consider the application of PCDs to this expenditure in circumstances where there would be no impact on performance against other RIIO-ED2 outputs if the allowance provided was not subsequently used to deliver the project and/or volume of capacity intended.	LRE's link to regulatory outputs is shown in **table 1**
5.19	N/A	
5.20	In proposing costs for operating and developing their networks, companies should explain their costs/workload forecasts, particularly where these diverge from historical trends.	Our material cost/workload changes are discussed in **section 6**
5.22-5.23	considered current and future levels of network utilisation in our analysis; considering a range of options in CBAs (incl. do nothing); use of whole system analysis; taking a flexibility first approach in our CBAs; consideration of investment timing	How we populated options for assessment is described in **Section 5.3** and our network utilisation forecasts and how we used timing are shown in **section 5.4**
5.24	risk of under utilisation/stranding that new/existing investments might face in the future under a range of plausible forecast scenarios	Our stranding analysis is in **section 5.4**
5.25	For new or existing assets that face a risk of underutilisation, Business Plans should set out the monitoring and mitigation they will put in place to reduce this risk.	Our stranding analysis is in **section 5.4**
5.26	Where a DNO considers an investment is certain under all scenarios, they will be expected to provide justification for this view.	This is covered by our constraint analysis in **section 5.3** and by our funding proposal in **section 5.5**
5.27	Business Plans should demonstrate how their expenditure forecasts map onto relevant ODIs and PCDs	Our link to ODIs and PCDs is shown in **table 1**

Appendix B ENHANCED ENGAGEMENT

LOCAL NETWORK PLANS

- Overview: **We plan to meet increased demand on our network from low-carbon technologies**
- Total cost: **£393m** (total load-related expenditure)
- Contribution to annual customer bills: **TBD for Final**
- Benefit to customers: **£80m carbon benefits and £90m financial benefits over one year, enabled by ensuring LCT customers are able to connect on time. We expect these benefits to recur over each year of the ED2 period and beyond.**

RIIO-1 context

In 2019/20 we served 782,536 customers across our North of Scotland region (up 4,232 from the previous year), and 3,092,275 customers in our central Southern England region (up 24,287 on the previous year).

Our challenge for ED2 is to be proactive about readying local networks to accommodate increasing demand that will come from the electrification of heating and transport required to achieve the net zero transition, while optimising reinforcement. Failure to provide sufficient capacity at the right place, and at the right time, is likely to lead to inability to meet net zero demand requirements. Investment must be timed so as to deliver long-term value to customers whilst being mindful of bill impacts – especially for those in vulnerable situations who must not be left behind in the push for net zero.

ENGAGEMENT SYNTHESIS

Engagement summary

Engagement details	Insights derived
Scottish Government (Energy and Climate Change Directorate) We collaborated with the Scottish Government through a series of bilaterals to identify the most appropriate Distribution Future Energy Scenario (DFES) to use as a baseline for ED2 planning	• The Scottish Government see that we have a substantial role in supporting their statutory targets. [E107] • The Consumer Transformation DFES scenario is most closely aligned with the Scottish pathway to net zero, although Leading the Way is also relevant. [E107] • For battery electric vehicle (EV) uptake, the expectation is that the future pathway will be between the Consumer Transformation and Leading the Way DFES scenarios. [E107] • For the decarbonisation of heating, while the Consumer Transformation scenario is closest to the ambition, there is likely to be a need to go further and faster than this. Reliance on hybrid heat pumps (from Leading the Way) does not correspond with their plans. [E107] • Renewable generation capacity is projected to be between Consumer Transformation and Leading the Way scenarios so

	the ability to flex these both up and down to meet the outturn is important. [E107] • It is considered likely that there will be distribution connected electrolysis in the North of Scotland, with strong potential for areas such as Aberdeen [E059].
Local Authorities We collaborated with stakeholders via bilaterals to identify how we should identify the most appropriate DFES to use as a baseline for ED2 planning and via virtual roundtables. We then co-created LNPs by providing LAs with DFES data for their area for EVs, Heat Pumps (HPs), PV, and battery storage and asking them to assess which DFES most closely matched their plans	• Ongoing communication and collaboration between us and Local Authorities (LAs) is essential. [**E063**] • Referencing UN Strategic Development Goals (SDGs) allows other LAs to align their principles to ours when tendering for services to support their own decarbonization projects/policy. [**E063**] • Stakeholders agreed that defining LNP area scope by Regional Economic Partnership (in our Northern region) and Local Enterprise Partnership (in the Southern region) areas is appropriate [**E063**] • We should consider network balancing as part of the LNP to identify opportunities for local generation. [**E063**] • LNP development should start by reviewing Local Plans to understand where capacity needs to increase. [**E063**] • 17% of councils responded with the evidence we sought, selecting Consumer Transformation (25% of those who responded) or Leading the Way (42% of responses) or a midpoint between these (16% of responses) scenarios in most cases. [**E106**] • 10% of councils told us that they could not provide a response or could not do so yet.[**E106**] • Some LAs are working in regional groups on their climate change response, for example, Oxford city, Vale of White Horse, West Oxfordshire and South Oxfordshire; BCP Council (Bournemouth, Christchurch and Poole) is producing a single plan with Dorset Council. [**E106**] • We are maintaining an open relationship with LAs together further evidence as their plans develop. [**E106**]
Local/community energy schemes, Consultants/Contractors, Local authorities We worked with Regen to engage stakeholders via separate online workshops for our North and South regions plus a follow-up survey to co-create projections for future network capacity based on a number of factors	• It was noted by local authorities that local government can supply local information and help mold plans but SSEN needs to inform on requirements to meet 1.5C targets [**E062**]. • Local authorities expressed the view that we should engage with them, local energy agencies, local developers, and should look at Local Energy Plans [**E062**]. It was also stated that we need to inform on what is necessary to meet 1.5c then understand what can be done locally to achieve this [**E062**]. • On several occasions local authority representatives thought local government needs to engage in conversation and provide as much evidence as possible. However, it was accepted they were short in resource and time and may not be able to provide sufficient evidence for reinforcement decisions [**E062**].

	• 75% of local authority representatives that participated in the local network plan survey agreed with our approach of using credible 'base' scenario for electricity demand on the network and modifying where there is strong local evidence [E062]. • 88% participants in the same survey felt that adjusting network plans and investment aligned with local authority plans was a fair approach given investment costs will be socialised across consumer groups and geographies [E062]. • Stakeholders encouraged us to collect evidence for network planning through public consultations with Community Councils [E062]. • A stakeholder fed back that they have no current plans to increase their current biomethane production [E059].
Community interest groups We conducted online roundtable discussions with small numbers of stakeholders in Tayside and Thames regions to co-create what we need to include in our Local Network plans to allow them to deliver their climate targets, and to shape approach to future stakeholder engagement on LNPs	• LNPs and investment should be adjusted to align with LAs' different policies and development paths for achieving Net Zero. [E063][E064] • We should consider how gas and other energy vectors might factor into the creation of LNPs. [E063][E064] • UN SDGs should be referenced in LNPs to ensure consistency at all levels. [E063][E064] • Co-ordinate improvements in energy efficiency of buildings with substation reinforcement plans to achieve cost-effective investment decisions [E063][E064].
Developer/Connections representatives We conducted online roundtable discussions with small numbers of stakeholders in Tayside and Thames regions to co-create what we need to include in our Local Network plans to allow them to deliver their climate targets, and to shape approach to future stakeholder engagement on LNPs	• We should work with housebuilders to promote electric heating [E063][E064].
Local Enterprise Partnerships We conducted online roundtable discussions with small numbers of stakeholders	• LNPs should understand the policies of different LAs, for example, with regard to electric vehicles and heat pumps [E063][E064].

in Tayside and Thames regions to co-create what we need to include in our Local Network plans to allow them to deliver their climate targets, and to shape approach to future stakeholder engagement on LNPs	

Green Recovery stakeholders (local authorities, community energy schemes, DG and storage providers, housing developers, motorway service area operators)
 	
We engaged with connections customers via webinar broadcasts, bilaterals and a Call for Evidence to this Government scheme which provided an additional layer of ED2 LNP insight
	• Stakeholders shared plans for over 150 low-carbon demand (mainly EV chargepoints) and generation/storage projects across both of our license areas which were challenged by distribution network constraints and, in many cases, by further transmission network constraints. These projects were limited in scope to those which could be delivered in the next 2-3 years so are indicative of levels of growth rather than specific ED2 requirements. There were notable concentrations of constraint in:
	  ○ The Outer Hebrides, Dundee and Aberdeen in the North of Scotland
	  ○ Dorset and the M4/Heathrow area for demand and Wiltshire/Gloucestershire for generation in our Southern Licence Area. [E144]

Consumers We tested domestic and non-domestic customers' priorities for 15 initiatives separately for the North and South Licence Areas via a robust Willingness to Pay study	• Increasing the number of new low carbon heat pump connections made by the end of ED2 from 235,000 to 800,000 is a high priority for all customer segments and a very high priority for non-domestic customers in the South relative to other initiatives [E126]. • Increasing the number of new electric vehicle connections from a basic level of 675,000 to 1.3 million is a high priority relative to other initiatives for all customers in the South and a medium priority for those in the North [E126].

Synthesis and Implementation of insights

What do the majority of insights suggest?

All stakeholders are strongly in favour of LNPs being localised by incorporating local policies, geography, social factors, and electrical and other infrastructure, as well as projected growth in local demand and generation under Distribution Future Energy Scenarios (DFESs). For each of our LNPs, we commissioned a study to apply weights to adjust the DFES Consumer Transformation baseline plan to reflect low carbon technologies. We further engaged with local authorities to understand whether we should make further adjustment but none were identified and therefore we applied the Consumer Transformation scenario.

Stakeholders also seek permanent routes to collaborate with us as plans evolve and future uncertainties become clearer. We will establish a forum for ongoing dialogue with LNP stakeholders to help avoid constraints ahead of time amongst other benefits.

What does the most robust source suggest?

LAs are the most robust source. The Scottish Government is clear that the Consumer Transformation DFES scenario is most closely aligned with the Scottish pathway to net zero, although Leading the Way is also relevant.

Are there any groups we need to pay particular attention to? (Example: would one group be disproportionately impacted? Are some insights from experts in the field?)

The statutory requirement for LAs to meet net zero targets means that their views must take precedence (for example, over customer sentiment on bill impact, which is yet to be gathered). As planning authorities, they are experts in the field. While their views are key because they are responsible for area infrastructure and economic development, the involvement of community interest groups in providing detail is important as the energy system becomes more democratised.

Does our proposal diverge from any insights? (Why are we discounting these? Are we more convinced by other insights? Are there other factors leading us to a particular decision?)

See Evidence triangulation section below.

EVIDENCE ASSESSMENT

Engagement scoring key

The engagement score assigns a weight to each source accounting for the robustness of the engagement event and the relevance of the feedback to the topic.

Overall Score	Description
1-1.66	Limited evidence of good event planning, methodology or data collection. Feedback provided is high level with tangential relevance to the topic.
1.67-2.33	Good evidence of engagement planning and discussion of data collection methods, but limited depth of feedback and range of opinions. Feedback not necessarily fully aligned to the topic and only provides a limited insight and thus moderately useful.
2.34-3	Well conducted, trustworthy event with highly relevant feedback. Specific, clear and relevant information with clear link to the topic discussed and high value added.

ED2 ENGAGEMENT EVENTS

15

INSIGHTS

155

STAKEHOLDERS ENGAGED

1,587

Phase	Date	Event ID	Event Name	Key Stakeholder Groups	# of Stakeholders Engaged	Engagement Score
Placeholder for further engagement						
Phase 3: Business Plan Refinement	May-21	E127	Sustainability bilateral Thames Water	Water	2	1.3
	May-21	E126	Willingness to Pay Quantitative report	Domestic customers, customers in vulnerable situations, next generation bill payers, SMEs	1,161	2.5
	Mar-21	E144	Green Recovery Scheme Call for Evidence	EV charging, Storage and renewables, Community energy schemes, Builders and developers	60	1.7
	Mar-21	E125	Willingness to Pay Qualitative testing	Domestic customers, customers in vulnerable situations, next generation bill payers, SMEs	54	2.5
Phase 2: Co-creation	Jan-21	E106	Electricity Networks Distribution Future Energy Scenarios - Local authorities	Local authorities	12	2.0
	Nov-20	E042	Corporate affairs - 3rd Sector engagement	Consumer groups	1	1.0
	Nov-20	E062	Local Network Plan follow on survey	Local authorities, consultants	8	2.2
	Oct-20	E041	Corporate affairs - Political stakeholder engagement	National government	15	1.0
	Sep-20	E059	Regen Local Network Plan Workshops - North	Local authorities, consultants, community energy schemes	67	3.0
	Sep-20	E060	Regen Local Network Plan Workshops - South	Local authorities, consultants	105	3.0
	Sep-20	E072	Annual Stakeholder Workshops - North	Local authorities, vulnerable customer representatives, housing associations	84	2.0
	Sep-20	E083	Distribution Network Planning under Uncertainty	Research bodies, policy forums and think tanks	1	3.0
	Jun-20	E063	Local Network Plans Pilot - Tayside	Local authorities, LEPs	8	2.3
	Jun-20	E064	Local Network Plan Pilot - Thames	Local authorities, LEPs	8	2.3
	Feb-20	E107	Electricity Networks Distribution Future Energy Scenarios - Scottish Government	National government	1	2.0

EVIDENCE TRIANGULATION

Triangulation meetings: April and June 2021

Triangulation criterion	Summary	Comments
Overall strength of evidence	Medium	There were five bespoke events discussing the Local Network Plans which provided reasonably extensive feedback from a range of stakeholders on the topic. Most of the feedback focused on different sub-topic areas at a high level, such as hydrogen deployment, expected wind deployment and EV deployments. This provides a good base for ongoing engagement where stakeholders may be able to discuss particular options and processes in more detail. LNPs were also discussed tangentially in other events.
Divergence of stakeholder views	Medium	There were differences between north and south regarding LCT deployment, with the north focusing more on wind generation while the south focused more on solar PV generation. There were some deviations in views regarding how well-placed each region was with LCT as well as how different technologies should be applied and integrated on the network in future. There were some differences in opinion surrounding local vs national decarbonisation plans as well as data sharing between areas, especially between stakeholder segments.

TRIANGULATION OUTCOMES

Triangulation assessment Key

Findings converge to support proposals.

Findings generate new insights that lead to further refinement of proposal.

The proposed approach diverges from the findings.

Proposal area	Stakeholders said	Our response	Output/s
DFES baseline scenario	Most LA stakeholders did not have sufficiently developed plans themselves to be able to select a DFES	We have selected Consumer Transformation as the baseline scenario for ED2. Our funding proposal is based on Consumer Transformation only for the first two years of ED2 because of uncertainty, and so we are ready to respond to a range of potential pathways.	LC1

MEASUREMENT OF SUCCESS

Output	Northern Target	Southern Target	Comparison to RIIO-1	Cost	Benefits to customers
LC1: We will invest in flexibility services and network solutions to enable the timely connection of Low Carbon Technology with the aim to achieve c.1.3m Electric Vehicles and c.800,000 heat pumps during ED2.	EVs: c.170,000 HPs: c.215,000	EVs: c.1,130,000 HPs: c.585,000	N/A	£393m (total load-related expenditure including EV/HP enablement)	£80m carbon benefits and £90m financial benefits over one year enabled by ensuring LCT customers are able to connect on time. We expect these to recur for each year of the ED2 period and beyond.

LOCAL AUTHORITY DFES ENGAGEMENT APPROACH

To further enhance the scenario modelling and to allow stakeholder engagement to continue, we approached Local Authorities[38] with the results of the DFES projections to create a modified baseline scenario. The relevant data for each Local Authority (LA) was provided with a request for LAs to self-select the scenario which best represents the local (LA) view of the projection for four of the most impactful low carbon technologies.

All Local Authorities have been asked to evidence their selection, with each being assessed in accordance with an open and transparent evidence assessment framework summarised in Table 26.

- Where evidence met the required quality, the baseline DFES was subsequently adjusted (up or down).
- Where evidence did not meet the required quality threshold or where the local authority had no clear view, the forecast was defaulted to the local baseline.

Table 26 - summary of SSEN's load-related investment in the ED2 period by reporting category

Criteria	High Marking		Low Marking	
Policy/Ambition	++	Self consistent	--	No narrative available
	++	Clear objectives	-	Exists but poorly articulated
	++	Overall pathways identified	-	Piecemeal
	++	Links to wider government policies.	-	Internal contradictions
	++	Referenced, supported by and supportive of wider economic and social policy.	-	Limited narrative for delivery.
	++	Statutory and legally binding	-	Does not link to wider economic / social policy.
	++	Aspirational but with clear policy levers and/or financial support.	-	Aspirational and without indication of how they will be delivered.
Financial support	++	Financial support committed in budgetary process which has received parliamentary / council agreement.	--	No indication of finical support.
	+	Plans for financial support clearly laid out with pathway to delivery.	-	Only vague indication of financial support without commitment.
Delivery commitment	++	Formal commitment from business and third sector organisation to support delivery.	--	Evidence that business and third sector do not support the target or policy.

38 This occurred in January 2021 and will continue as part of Final Business Plan submission and thereafter as part of regular business-as-usual planning processes.

	+	Evidence of ambition from business and third sector organisation to support delivery.	-	Evidence that business and third sector are not aware of the target / ambition.

This approach allowed us to capture the evidence and views of our stakeholders ahead of any final decision on the ED2 expenditure plan and to create a baseline scenario detailed enough to capture potential differences in technology forecasts for each local authority. Figure 27 shows the approach.

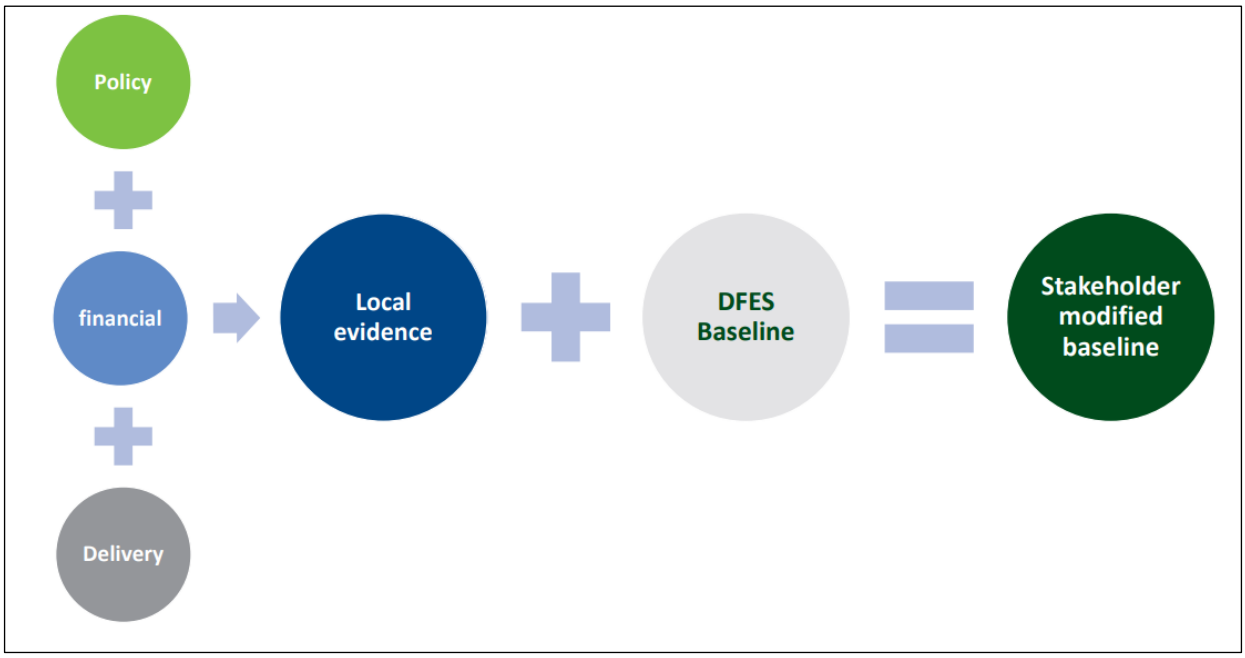

Figure 26 – Stakeholder modified baseline process

By consulting stakeholders early, creating evidence-based forecasts and communicating the results for further consultation, we have been able to create a well-founded projection of the energy changes in our licence areas.

LV

- Overview: **The LV network is key to delivery of our ED2 outcomes**
- Total cost: **Included in budgets for various workstreams**

RIIO-1 context

The LV network is expansive across both licence areas and accounts for a significant portion of the value of our regulatory asset base.

Installation of LV monitoring and smart meters is providing data to help us understand how our network is configured, how it performs, and improving our visibility to enable us to better correlate local generation with customer demand.

Data analytics is being undertaken to understand how we can make best use of available data and draw from existing knowledge.

As of June 2021, we have procured over 700 LV monitors and a rollout programme is underway to install these at sites selected based on network capacity and EV chargepoint installations.

ENGAGEMENT SYNTHESIS

Engagement summary

Engagement details	Insights derived
Other supply chain We conducted audience research with these stakeholders via an online workshop to co-create our LV monitoring approach and procurement process, and via a survey following up a general supply chain engagement event	• Stakeholders want us to continue with their current annual targets for monitors as they are achievable [E057]. • Stakeholders were at best ambivalent about using 'transformer capacity utilisation' and 'feeder capacity utilisation' as a basis for monitoring installation, instead suggesting a number of alternative measures including power quality and fault patterns/frequency [E057]. • In addition to using LV monitoring to inform fault dispatch, stakeholders suggested that we should use 'unbalance', 'real time EV load', 'phase identification', 'real time data for fault prediction', and 'PV (or V2G/BESS) backfeed' [E057]. • A majority of stakeholders would prefer us to use a procurement approach which separated sourcing for LV monitoring device hardware from sourcing for software analytics platforms, and they would be happy to supply just one of these [E057]. • A minority of stakeholders highlighted that some solutions did not fit well with our preferred iHost interface, which discouraged some from tendering to supply LV monitoring equipment, but most stated that it did not present a problem for their solution and did not discourage them from tendering [E057].

	• When asked which of the 'New for ED2' categories suppliers believed is the most important in achieving an effective future network, 'low voltage monitoring' was one of the options stakeholders most commonly selected [E066].
Distributed generation customers, local authorities We engaged with stakeholders to co-create uncertainty mechanisms via a virtual roundtable	• A data-driven approach was seen as absolutely crucial to rolling out EV chargers, as different parts of our network would need different levels of reinforcement, and therefore large amounts of LV monitoring would be needed prior to any infrastructure roll-out or network reinforcement in order to ascertain how much reinforcement would be needed in each local area and where it would need to go [E068]. • Stakeholders were concerned with the monitoring of low voltage (LV) networks, particularly with the predicted increase of electric vehicles (EVs), as their chargers would be connected to LV networks – they urged us to address any results from LV network monitoring and ensure that it was intertwined with other UM approaches, such as strategic investment [E068].

Synthesis and implementation of insights

What do the majority of insights suggest?

Stakeholders advised that LV monitoring will be crucial in informing requirements of the network prior to roll out of future infrastructure, such as EV chargers. Although stakeholders agreed with our current targets for rollout of LV monitors, they made many additional suggestions when discussing our approach.

We will continue with our LV monitoring rollout and will implement our strategy of deploying monitors before networks/assets reach critical capacity by assessing this using a range of metrics suggested by stakeholders; we estimate that approximately 9,000 LV monitors may be required in ED2, averaging 1,800 installations a year.

Our LV strategy will allow us to leverage the use and value of LV Monitoring, and other Operational Technology (OT) data by developing data analytics tools to process and understand data that is collected. We will continue to deploy LV monitoring on the LV network in areas with high incidence of faults and to manage legacy issues. Monitoring will facilitate a safe and reliable LV network, flexibility, and improved understanding of our assets. It will also enable a smart, transparent LV network that is responsive to customer needs and interactions, and an efficient LV network capable of connecting capacity and accommodating LCT uptake.

What does the most robust source suggest?

Stakeholders indicated a preference for a procurement approach whereby monitoring software and hardware could be supplied to us separately.

Stakeholders identified areas of improvement for the iHost interface, with some telling us that this discouraged them from tendering for the supply of LV monitoring equipment because of it.

Are there any groups we need to pay particular attention to? (Example: would one group be disproportionately impacted? Are some insights from experts in the field?)

There is a strong demand for LV monitoring from different stakeholder groups.

Does our proposal diverge from any insights? (Why are we discounting these? Are we more convinced by other insights? Are there other factors leading us to a particular decision?)

See Evidence triangulation section below.

EVIDENCE ASSESSMENT

Engagement Scoring Key

The engagement score assigns a weight to each source accounting for the robustness of the engagement event and the relevance of the feedback to the topic.

Overall score	Description
1-1.66	Limited evidence of good event planning, methodology or data collection. Feedback provided is high level with tangential relevance to the topic.
1.67-2.33	Good evidence of engagement planning and discussion of data collection methods, but limited depth of feedback and range of opinions. Feedback not necessarily fully aligned to the topic and only provides a limited insight and thus moderately useful.
2.34-3	Well conducted, trustworthy event with highly relevant feedback. Specific, clear and relevant information with clear link to the topic discussed and high value added.

ED2 ENGAGEMENT EVENTS

3

INSIGHTS

12

STAKEHOLDERS ENGAGED

131

Phase	Date	Event ID	Event name	Key stakeholder groups	Number of stakeholders engaged	Engagement score
Placeholder for future engagement events						
There was no feedback on LV in Phase 3						
Phase 2: Co-creation	Mar-21	E068	UM south round table	Distributed generation customers, local authorities	10	2.0
	Nov-20	E066	Supply chain engagement launch event follow on survey	Other supply chain	100	2.0
	Oct-20	E057	LV monitoring supply chain workshop	Other supply chain, Transmission, Consultants, Service partners	21	2.5

EVIDENCE TRIANGULATION

Triangulation meetings: April and June 2021

Triangulation criteria	Summary	Comments
Overall strength of evidence	Weak	LV monitoring was discussed in one bespoke event and two other specialised events. Feedback was very limited at only 12 pieces of feedback and only three stakeholder segments were engaged. Further engagement specific to our LV strategy will be conducted after Draft submission.
Divergence of stakeholder views	Medium	As feedback volume was so limited and the range of stakeholders were also limited, the range of views was also limited. One detailed area of divergence was around the use of our preferred iHost interface, which a minority of stakeholders stated that it presented some issues with them when tendering.

TRIANGULATION OUTCOMES

Triangulation assessment Key

Findings converge to support proposals.

Findings generate new insights that lead to further refinement of proposal.

The proposed approach diverges from the findings.

Proposal area	Stakeholders said	Our response	Output/s
Use of iHost interface	A minority of stakeholders highlighted that some solutions did not fit well with our iHost interface, which discouraged some from tendering to supply LV monitoring equipment, but most stated that it did not present a problem for their solution.	Although iHost is an issue to some, we will continue to use this interface, which is a proprietary system used throughout the industry, because a substantial majority of suppliers found it fit for purpose. We believe it is central to creating a supplier-agnostic approach, and are working with stakeholders to create enhancements that will deliver this as BAU.	N/A

MEASUREMENT OF SUCCESS

Successful delivery of the LV strategy will be achieved through provision of direction to workstreams who will deliver customer benefits through ED2 outcomes. As such, success is measured through workstream metrics and outputs.

A key feature of the ED2 business plan is the implementation and roll out of LV flexibility services, as part of our transition to DSO, and so it is vital that we test and stimulate this marketplace to understand the impact that flexible operation could have on the health of our LV assets.

Appendix C LOAD MANAGED AREAS (LMA)

Load Managed Areas (LMA) in SHEPD cover approximately 87,000 customers, spread right across the geographic licence area, including the islands and many densely populated towns and cities. LMA reduce the maximum demand on circuits at all voltage levels and at substations by effectively smoothing demand over the 24-hour period. Currently, space heating and water heating load are independently controlled at different times during day and night via Long Wave Radio Tele-Switching (RTS).

Background and context

It was originally planned that suppliers replace all RTS meters with SMART meters by April 2020. Ofgem agreed under DCP 326 to replace RTS with pre-programmed SMART meters. This was not achieved, and targets were missed by suppliers and the smart meter programme. The need for additional controls on SMART meters contributed to the delays.

LMA serves an important role enabling and supporting the connection of large amounts of space and water heating without triggering costly network reinforcement in the SHEPD licence area. These emerged in the 1970s when companies were integrated (generation, supply and networks) and were keen to maximise benefits of cheaper overnight wholesale (e.g. nuclear) electricity and spare network capacity. It was also a time in North of Scotland when there was a push to get customers onto electric storage heating and off costly oil, peat, and coal – especially for the many in Scotland at the time who could not access the gas network.

LMAs are becoming increasingly misaligned with the direction of travel for electricity distribution in the UK on a number of counts:

1. Reliance on static tariffs designed for the nuclear era rather than dynamic tariffs emerging to respond to flexibility market and renewable intermittency;
2. Provision of a level of flexibility service with no direct reward for the customer providing the flexibility;
3. Representing an additional barrier to customers switching supplier by effectively locking customers into specific tariffs, therefore driving-up energy costs[39];
4. Creation of a two-tier customer experience which could be interpreted as a 'post code lottery'; and
5. Undermines the opportunity for market provision of alternative flexible solutions, and consideration of any potential wider whole systems benefits to the national system or wholesale energy markets.

These factors and the desire for greater customer choice on tariffs, supplier switching and the continual drive to alleviate fuel poverty and customers in vulnerable situations, all provide for a compelling case for the removal of LMA.

ED2 priority will be to use flexibility as a first solution for LMA removal

LMA was introduced as an alternative to traditional reinforcement. LMA is a form of flexible solution for the provision of capacity but, unlike our arrangement for constraint-managed zones (CMZ), LMA provides no

[39] As identified by Citizens Advice Scotland.

reward for the provider of the flexibility, instead inadvertently penalising customers through obstructing access to the competitive supply market and potentially locking LMA customers into more expensive tariffs. We therefore believe that market solutions should be the first choice for enabling the lifting of customer LMA restrictions and the promotion of market-based flexibility services. Removal of LMA constraints through conventional constructed solutions (iron and copper) should be a last resort.

Our short-term (ED1) approach is to maintain switching patterns using smart metering via suppliers, as per current DCUSA obligation.

Our approach in ED2 will be to use market flexibility services to replace LMA mandated switching patterns – including activities to define, develop and stimulate the market – alongside, and in accordance with, development and facilitation of flexibility markets to support DSO. Solutions to provide additional capacity to support the uptake of LCT will be co-optimised with those to remove LMA restrictions – using the principle of 'flexibility first'. We will also ensure that all/any other reinforcement or flexibility procurement for other (non-LCT) needs or requirements provides for LMA removal, as a matter of course.

In ED2 we will therefore actively pursue flexible solutions which deliver value for money for customers on a whole system basis, taking full account the wider costs and benefits. We will initially signpost our flexibility requirements based on our understanding of the network constraint parameters represented by the existing LMA arrangements. This will allow flexibility providers time to design appropriate services including technologies such as flexible heat pumps, efficiency/flexibility packages and tariffs. As we understand network requirements in more detail – through the LV monitoring and analysis – we expect to be able to procure such services accurately, delivering benefits.

One solution to support LCT uptake (Net Zero) requirements and LMA removal

There will be a significant overlap between capacity solutions for LCT uptake and the potential capacity needed for removal of LMA. In considering the options to support LCT uptake we will integrate the capacity requirements associated with removal of LMA restrictions. We will apply our standard 'flexibility first' approach to the resulting composite demand profile to help understand the role that flexibility should take to optimise costs and benefits in relevant parts of our network.

At EHV, we have ensured that any planned reinforcement of primary substations (33kV/11kV) and circuits proposed as part of the ED2 Business Plan to accommodate low-carbon technology (LCT) uptake also support the removal of switching pattern restrictions on all LMA customers supplied from that substation. We are also confirming that all other primary substations are able to accommodate LMA restriction removal. At HV and LV we are extending the data-led 'hot-spot' analysis of all HV and LV circuits using the approach developed for LCT uptake in the ED2 Business Plan in order to ensure co-optimise additional capacity solutions across LCT and LMA needs – with a focus on procuring flexible solutions first.

An opportunity to focus enhanced LV monitoring and deliver additional customer value

A key part of our effort in ED2 will be to validate and calibrate our data-led analysis of LMA constraints on the LV (and HV) networks, and to understand the capacity intervention requirements – be it conventional or flexibility service – and customer behaviour, associated with end-to-end removal of LMA restrictions in a given community area. We will install LV monitoring and remove up to 1,900 customers from the LMA

register by reinforcing parts of the network associated with Constable Street Primary Substation in Dundee and Ormlie Primary Substation in Thurso. This will be funded through 'Green Recovery' and will allow us to hone our methods and allow flexibility service providers to understand the requirements. Combining this strategy with the current industry LMA solution, the existing planned investment due to LCT and our plans to expand network analytics and modelling will, we believe, allow us to reduce LMA restrictions more rapidly.

Methodology for establishing the justification of this proposal

The case made above for removal of LMAs focusses on a number of qualitative and quantitative benefits, the suggested methodology for assessing these can be found in Table 27.

Table 27 – Methodology for assessing benefits of LMA removal

Types	Benefit Title	Description	Method of quantification
Customer saving	More competitive supplier energy costs (through avoiding tariff limitations)	Customers of Total Heating, Total control (THTC) are locked into tariffs. The LMA limits the tariffs that suppliers can offer and there is no compensation offered.	Draw on work being undertaken by Citizens Advice Scotland (CAS) to inform the determination of customer financial costs and benefits. This will include an assessment of the proportion of these customers that are classed as 'fuel poor'.
Customer saving	New revenue from flexibility service provision products	Customers will be free to participate in arrangements that may provide reward for providing flexibility for wider whole systems benefits to the national system or wholesale energy market (via their supplier). This is particularly relevant in that most RTS customers have thermal storage installed.	Seek third-party assessment of potential customer benefits – possibly though CAS.
SSEN reputational	Reputational Damage	LMA will increasingly be recognised as a means for DNOs to acquire flexibility without paying for it. This conflicts with a number of directives including the Clean Energy Package and as such should to be tested against a market-based alternative.	Assessment of potential compliance risk.
SSEN saving/customer saving (indirectly)	Deferred network reinforcement	Currently SSEN pays the largest proportion of costs for the maintenance of the Low Wave RTS system as the main benefactor of the system.	The existing RTS system although controllable is relatively inflexible in practice. Through the improved granularity that we can obtain from Flex Services we get more headroom from our Network assets.
Internal Saving	RTS Optimisation and cost reduction	The operation of RTS in LMAs has always been problematic with associated overhead and operation costs	Removal of costs associated with RTS (although unlikely to cover cost of procuring flexibility)
Internal Savings	Reduction in costs of operating diesel generation	Diesel generation used at times of network fault will need to meet a more controllable demand profile.	Complete a study of the optimal savings in station running costs that could be achieved through improved flexibility.

Types	Benefit Title	Description	Method of quantification
			(Western Isles, Orkney, Shetland, Islay, Tiree)
CI/CML back-feed resilience	Circuit-specific back-feed load management	Increased opportunity to use flex at time of fault to enable use of (partial) back-feeds (e.g. Grudie Bridge, Kilmelford) to provide required levels of security (e.g. n-1)	Undertake a study to quantify the value on a probabilistic basis of flexing demand at times of fault.

Regulatory treatment in ED2

The volume and cost of flexibility needed is currently unknown as the market is in its infancy. We will therefore be seeking an appropriate regulatory uncertainty mechanism to fund this activity in ED2, so as to manage this uncertainty in a way that delivers maximum value to customers (e.g. similar to Gas Fuel Poverty). This mechanism can be informed by reference to the CBA which captures the whole system cost of continuing LMA, including the assessment of any associated customer detriment and broader societal and community costs.

Finally, the end of ED3 will mark the time backstop for complete removal of all (imposed) LMA constraints across SHEPD licence area.

A summary of our five [5] element hierarchy of strategic solutions for the phased removal of LMA restrictions is set out in Table 28.

Table 28 – Summary of proposed approach to LMA removal.

Short-term (ED1)	1. Maintain switching patterns using smart metering via suppliers (as per current DCUSA obligation)
Medium-term (ED2)	2. Use of market flexibility services to replace LMA mandated switching patterns 3. Co-optimise with additional capacity solutions (LCT) for the uptake of LCT – using flex first principles 4. Ensure that any other network expenditure (LRE and NLRE) or flex procurement for other (non-LCT) needs or requirements provides for LMA removal
Longer-term (ED3)	5. End of ED3 as a time backstop for removal of all LMA constraints

Next Steps

In preparation for the removal of LMAs we have set up a Project Steering Board to manage the process starting with determination of the flexibility requirements, design of the flexibility Services requirements, engagement with potential flex providers (including suppliers), preparation of the flex tender exercise, LCT network investment alignment.

Where required we will consider the use of NIA funding to resolve any residual barriers to the LMA removal programme.

Appendix D LOW VOLTAGE STRATEGY

1. WHY DO WE NEED AN LV NETWORK STRATEGY?

1.1. OUR STRATEGIC OUTCOMES

At Scottish & Southern Electricity Networks (SSEN) our stated purpose is that *we power communities to thrive today and create a net-zero tomorrow*.

To support our purpose, we have set out the following Strategic Outcomes:

- Accelerated progress towards a net-zero world
- A valued and trusted service for our customers and communities
- A safe, resilient, and responsive network
- A positive impact on society

The Low Voltage (LV) network is strategically important for reaching net-zero and will be a focal point of investment in ED2 and into ED3 and beyond. The ongoing decarbonisation efforts of the energy industry will see enormous changes on LV networks, particularly as organisations work together in a whole system way to electrify heat and transport down to the domestic level. Section 3.2 outlines some of the key changes expected on our networks over the next decade.

We have relatively poor visibility (in terms of data, information and understanding) of our LV networks, compared to what we know about our HV and EHV networks. Our LV networks were designed and built to conservative planning standards assuming unidirectional power flows, specifically to ensure adequate capacity for all customers, meaning that visibility was not necessary nor a high priority.

With a fundamental shift in demand patterns underway, and more small-scale generation connecting locally, visibility is becoming increasingly important. We need to know much more about our LV network if we are to deliver on our purpose and strategic outcomes. Improved visibility will allow us to manage voltages and power flows, and to perform swift remedial action to improve resilience and invest efficiently.

The transition to Distribution System Operator (DSO) and increased use of flexibility services at LV will also see more active participation from a broader range of stakeholders and it is vital that the right systems are in place to enable this whole system working.

1.2. PURPOSE OF THE DOCUMENT

1.2.1. WHAT IT IS

This LV Strategy document sets out the overarching strategy to develop our LV network. It aims to ensure we continue to deliver a safe, reliable, cost-effective service to our customers, while at the same time enabling the electrification of heat, transport and facilitating active and equitable customer participation throughout our licence areas.

It is intended to offer guidance and strategic direction across the range of business areas within SSEN Distribution to ensure that activity and development on the LV network is coordinated and aligns with our purpose and our LV Strategic Outcomes.

The LV Strategy is complementary to our existing strategies and policies and will also form part of our ED2 submission to demonstrate and support our proposed investment in the LV network for the upcoming price control period.

1.2.2. WHAT IT ISN'T

The document is not intended to provide any specific technical, commercial or policy details on the LV network or advise on how specific initiatives or projects should be managed or delivered. SSEN policy documents can be accessed in the Document Management System.

1.3. TIMESCALES

The core of this strategy document sets out what we want to achieve, and how we plan to achieve it, over the period from now until 2030. The document will be updated periodically to keep it relevant.

2. WHAT INFLUENCES OUR LV STRATEGY?

2.1. EXTERNAL INFLUENCES

2.1.1. GOVERNMENT POLICY AND AMBITION

Government-level ambition, targets and legislation have an impact on the electricity sector, and they can have a huge influence on the timescales of change. These ambitions and targets also drive the need for us to work collaboratively with others across the whole electricity system (e.g. with gas companies to decarbonise heat), and with stakeholders in other sectors (e.g. working with the transport sector to deliver EV strategies).

A good example of government policy which will have a significant impact on the LV network is the ban of the sale of petrol and diesel vehicles by 2030[40]. This presents a challenging timeframe for SSEN, however, we are addressing this challenge in our ED2 business plan, where we set out our plan to work with the transport sector to prepare our LV networks to accommodate a large number of EV charge points and devise innovative solutions to enable this transition.

The Ten Point Plan for a Green Industrial Revolution[41] and the subsequent 2020 Energy White Paper "Powering our Net Zero Future" also set out ambitious targets across generation, demand, digitalisation, and customer engagement. These documents will feed into how SSEN strategic development is undertaken, and how we work with others to support the delivery of ambitions and targets across the whole electricity system.

Furthermore, there are both existing and forthcoming legislative requirements that influence our LV Strategy.

2.1.2. REGULATORY PRICE CONTROL

The Ofgem price controls influence how DNOs plan and invest in their networks, and the upcoming RIIO-ED2 (Revenue = Incentives + Innovation + Outputs) price control will determine how we can and should invest in the LV network throughout the coming decades. We believe that the forthcoming price control will be one that will see significant change and investment on the LV networks. The process of preparing our RIIO-ED2 ("ED2") business plan has already highlighted numerous opportunities and challenges that must be addressed to ensure prudent and efficient expenditure decisions are made in respect of owning and operating our LV Network.

2.1.3. THE DSO TRANSITION AND THE USE OF FLEXIBILITY SERVICES.

The transition to a Distribution System Operator (DSO) is already underway. We set out our plan for Our Transition to DSO in 2017 and our plan on Delivering DSO in 2019[42]. The transition is part of a coordinated Whole System effort from all UK Distribution Network Operators (DNOs), supported by the Energy Networks Association (ENA) and the Open Networks project[43].

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40 https://www.gov.uk/government/news/government-takes-historic-step-towards-net-zero-with-end-of-sale-of-new-petrol-and-diesel-cars-by-2030

41 https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution/title

42 https://www.ssen.co.uk/SmarterElectricity/

43 https://www.energynetworks.org/creating-tomorrows-networks/open-networks

This transition will see unprecedented changes in how distribution network companies will operate and manage the LV network, and in how our customers will interact with the network and with our business.

The transition to net-zero, and the associated network challenges, represent a key driving force for innovation and flexibility. It will ultimately change the traditional operating philosophy of distribution networks, and the way distribution networks work with others – for example, through our Whole Systems strategy and approach[44]. This in turn will allow electricity distribution businesses and customers to actively respond to situations through efficient use of existing network assets and a variety of new technologies and services.

2.1.4. WIDER INNOVATION AND TECHNOLOGICAL DEVELOPMENTS

The energy transition is bringing about significant changes across the energy sector. We are seeing rapid technology advancements (such as in battery technologies) and the development of innovative solutions to emerging challenges. The challenges we face are not unique to SSEN, and there is a real opportunity for distribution network companies to work together, and to work with stakeholders across the energy and other sectors (e.g. local authorities, transport, water, telecoms) in a Whole System way to share knowledge and expertise to solve problems. Further details on our Whole System strategy are provided in our *Enabling Whole System Solutions* business plan annex.

In Great Britain (GB), the Ofgem-funded innovation projects (Low Carbon Networks Fund (LCNF), Network Innovation Competition (NIC) and Network Innovation Allowance (NIA) are geared towards collaboration and knowledge sharing. These projects have already yielded excellent collaborative relationships and workable solutions to challenges that can be applied across networks.

It is important for us to maintain our focus on innovation and work with other DNOs and industry partners to develop solutions and exercise best practice in adopting new technologies.

developments

2.2.INTERNAL INFLUENCES

2.2.1. NETWORK TOPOLOGY

This LV Strategy applies to both the Southern Electric Power Distribution (SEPD) and Scottish Hydro Power Distribution (SHEPD) licence areas.

The SEPD area is densely populated, while the SHEPD area stretches over a vast and varied geographical area.

There is more extensive LV overhead network in the SHEPD region while the LV network in the SEPD region consists primarily of underground cables. The approach to managing and maintaining these assets is fundamentally different.

The LV Strategy applies to both licence areas.

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44 ED2 Business Plan (Draft), Chapter 14 and Annex A18.

2.2.2. LEGACY NETWORK ASSETS

The characteristics and challenges associated with the existing network will significantly influence the strategy needed to deliver the medium-term strategic outcome.

There are a number of issues and challenges with existing assets which influence how the LV network needs to change and evolve in future. This includes risks associated with known and recurring defects and faults associated with certain cable types (e.g. CONSAC), rating limitations associated with looped services, low capacity (e.g. 15kVA) pole-mounted distribution transformers – as well as legacy issued associated with phase balancing.

2.2.3. STRATEGIC OUTCOMES

The business Strategic Outcomes have shaped and influenced this LV Strategy.

The outcomes are particularly relevant for LV where interaction with customers (and the public overall) is most visible. This presents a real opportunity for SSEN to become the *valued and trusted service provider* making a *positive impact on society* by providing *a safe and resilient network* as we *progress towards a Net Zero World*.

The key will be working with customers and communities and ensuring they are part of the journey.

2.2.4. ALIGNMENT WITH WIDER SSEN STRATEGIES

The LV Strategy aligns with other SSEN business strategies, all of which are working towards the same Strategic Outcomes. Below is a list of some of the key strategies that the LV Strategy will complement.

- *ED2 Load-Related Strategy*. Alignment with overarching load-related strategy is key to ensure support and facilitation of Net Zero in a way that delivers immediate benefits and long-term value to customers.
- *ED2 Non-Load/Asset Strategy*. Close linkages with asset strategy will ensure LV asset maintenance and reinforcement is undertaken according to asset strategy (unique to asset type).
- *Connections Strategy.* Consistency and alignment with cost-apportioned reinforcement and LCT strategic investment in general (no double-counting) will be critical at LV.
- *DSO Strategy*. DSO functionality and the use of Flexibility Services and Flexible connections at LV will be hugely important, and likely very valuable and so the LV Strategy must be complementary to ensure that LV network is not a blocker for the development of flexibility markets and other non-conventional solutions at LV.
- *Strategic Asset Management Plan (*SAMP*)*
- *Digitalisation Strategy*. This will support the increased monitoring and control required at LV, as well as the roll out of DSO capability.
- *Whole System Strategy.* Alignment of the LV Strategy with SSEN's approach for Whole System working in ED2 will enable better collaboration, improved efficiencies, and reduced duplication in delivering our LV strategy and working toward Net Zero. It also enables us to share knowledge and learnings with others, and for us to draw on external expertise to deliver our LV Strategy.

- *Losses Strategy*. Alignment here is crucial to ensure work on the LV network is carried out in accordance with the losses strategy to optimise network losses e.g. asset replacement with minimum sizes, and drive efficiency.
- *Sustainability Strategy*. Overall alignment on wider sustainability and Net Zero targets.
- *Innovation Strategy*. Supporting the transition of innovation projects into business as usual, specifically those seeking to improve LV network visibility and performance, will be a huge enabler for accelerated progress on LV network improvements.
- *Data Strategy.* Strategically driving a programme of data quality management enabling our data to drive efficiencies and support best practice when working on the LV Network.

3.OUR LV NETWORK

3.1. WHAT IT LOOKS LIKE NOW

Headline statistics associated with our LV network are provided in

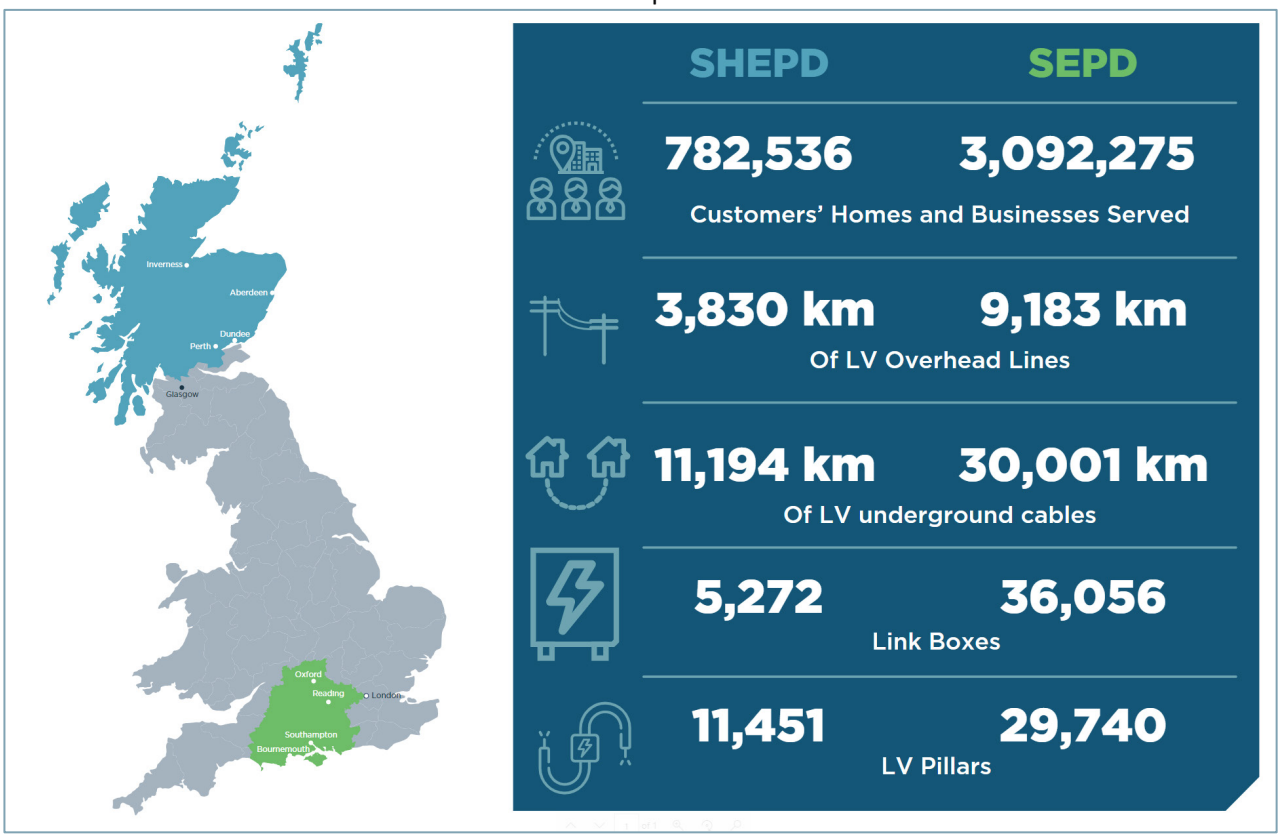


Figure 28.

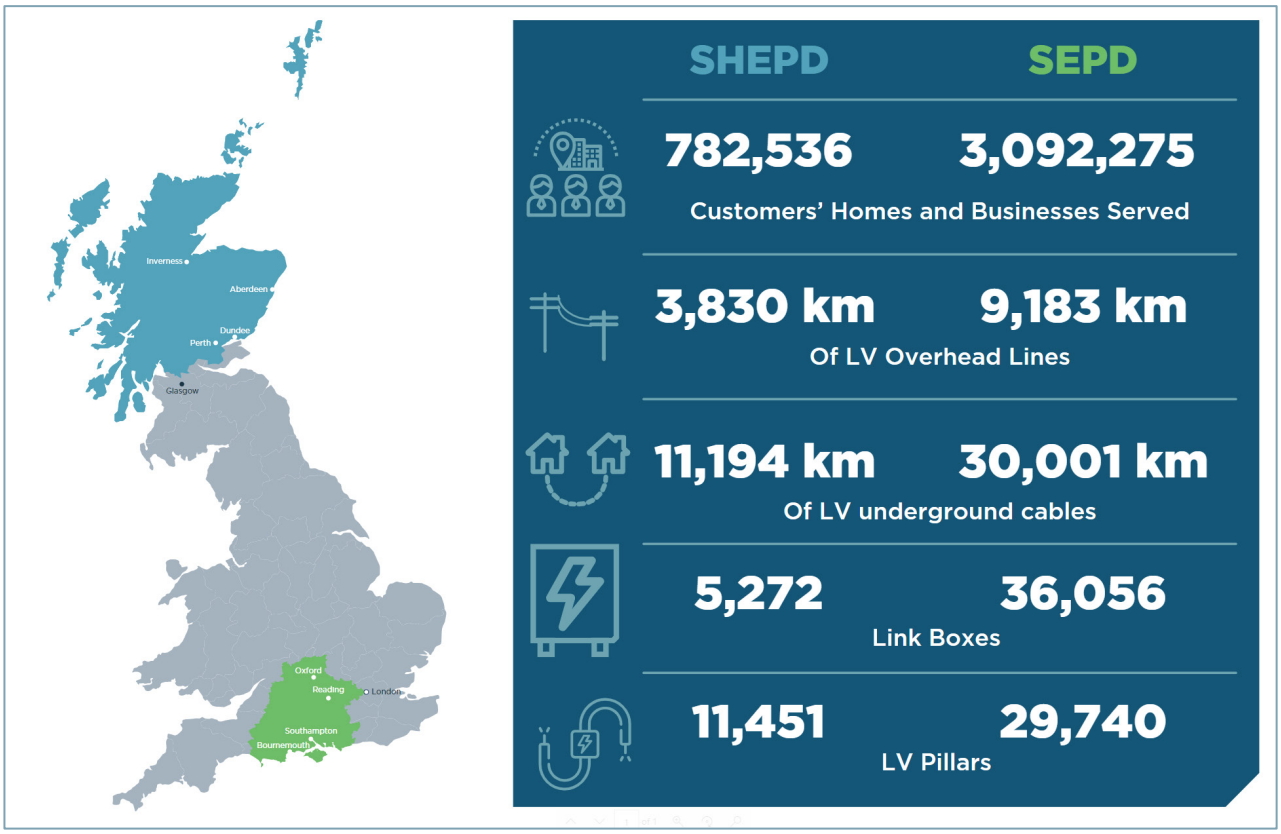


Figure 27 – SSEN's LV Network

The LV network is expansive across both licence areas and accounts for a significant portion of the value of SSEN's regulatory asset base.

3.2.DEVELOPMENTS TO 2030

Since 2018, SSEN has engaged Regen to support in the development of Distribution Future Energy Scenarios (DFES). These scenarios identify credible future pathways for our distribution business and to highlight the trends in energy generation and demand out to 2050.

According to our latest analysis[45][46] across all DFES scenarios it is expected that there will be in excess of 4.3 million EVs connected in SEPD by the 2040s and over 800,000 in SHEPD within the same time period.

The UK Government's commitment to stop the sale of petrol and diesel engine vehicles by 2030 is a significant contributing factor.

The switch of domestic and non-domestic heating to electric heat pumps is less certain, however there is still expected to be substantial uptake across both licence areas (potentially 1.7 million properties in SEPD and c. 700,000 properties in SHEPD) under some credible scenarios.

In addition, some 600,000 new houses are expected to be built in SEPD and around 112,000 in SHEPD across all scenarios by 2050.

45 Distribution Future Energy Scenarios 2020 Southern England licence area Results and Methodology Report, December 2020.

46 Distribution Future Energy Scenarios 2020 North of Scotland licence area Results and Methodology Report, December 2020.

As of the start of 2021, there were approximately 900,000 smart meters installed across the SEPD and SHEPD licence areas, against a target of around 3.7 million (i.e. every household). Industry view is that the benefits of smart meters and their accompanying data can start to be realised when a 60-70% penetration is reached (2.2 – 2.6 million). A 95% penetration roll-out deadline for smart meters has been set by BEIS indicating that at least 3.5 million smart meters will be installed on SSEN's networks by 2024.

From a network perspective, the uptake of new technologies (both generation and demand) and the electrification of heat and transport translates to a significant shift in daily demand patterns and an overall increase in maximum demand. Recognising that, it is an extremely difficult (and somewhat unnecessary) task to reinforce large parts of the LV network to provide enough capacity for this additional demand, opportunities to develop and deploy alternative smart techniques, such as flexibility services and demand side response (DSR), are actively pursued.

Flexibility would see customers participate in network operation and management by providing services to the DSO. This can be via smart Electric Vehicle (EV) chargers, or commercial agreements and tariffs to reduce demand during certain periods of time. The options for flexibility are wide and varied; there could be any number of interactions occurring at once to ensure the network is kept within its safe operational limits.

The anticipated Low Carbon Technology (LCT) uptake presents a significant challenge for us and our LV network.

The LV network comprises a significant proportion of old and ageing assets. These assets have been successfully operating in a passive manner (unidirectional power flows to serve customer demand) for decades. With the energy transition, and the changes that accompany it, we are now requiring our LV Network to operate in new ways, accommodating high levels of demand, bi-directional power flows and enablement and support for flexibility services. Our LV Network was not originally designed to deliver the types of load profiles and duty cycles that are beginning to emerge.

It must be acknowledged that there is a lot of work to be done to ensure the network is fit for purpose, and that this can realistically only be achieved through coordinated and incremental progression.

3.3. HOW TO GET TO WHERE WE WANT TO BE?

3.3.1. WHERE DO WE WANT TO BE?

We must continue to provide a safe, reliable, and cost-effective service to our customers while managing the significant changes that are expected over the coming years.

This means we have an obligation to enable our customers to connect new technology and interact with the network and the marketplace, all while minimising disruptions and consistently improving our customer service provision.

Gaining a better understanding our existing LV assets to support a prudent and efficient asset management capability is critically important. We must ensure that we optimise the costs and outputs of owning and operating our LV network assets – this includes careful and effective management of asset deterioration, required reliability levels, legislation change, climate adaptation, etc.

Significantly increased levels of customer engagement will be an important feature of operating the electricity distribution network in future. Openness and transparency will be key to facilitating a smooth transition.

From a customer service perspective, we want to be anticipating the needs of our customers, ensuring that the network capacity and the information they need is available at the right time. Our vision is that we will 'pre-assess' customers' LV services so that we can provide individual homes, or streets, with an 'LCT Readiness' status. All this will pro-actively promote LCT uptake and ensure that SSEN is not a barrier to net zero.

3.3.2. WHAT ARE THE BIGGEST CHALLENGES?

Some of the key challenges on the LV network are rooted in the **visibility** (of data and information) and better understanding of the **connectivity** of the network to an individual phase and individual home level itself. This is in addition to the health and condition issues associated with an ageing LV network.

The challenge and opportunity associated with visibility and connectivity are omnipresent, but they do vary with the business areas, for example:

- Operational staff working on the physical network can experience delays on site while they locate the correct cable in a trench to address a fault. This impacts Customer Minutes Lost (CML).
- The system planning and investment teams must make assumptions on long-term, potentially high-value, investment requirements. Sometimes based on limited data or evidence which will be subject to rigorous scrutiny from stakeholders and Ofgem.

There are some important challenges, such as the need to ensure that individual sub-strategies – such as that for tree cutting for example - align and coordinate in a way that delivers the target strategic outcomes for the LV network. Ensuring a single source of truth for data is also a critically important building-block for the future success of our LV network.

The LV Strategy seeks to address many of these challenges holistically and as efficiently as possible.

3.3.3. WHAT ARE WE ALREADY DOING TO OVERCOME THESE CHALLENGES?

There is already a lot of activity being undertaken on the LV network to address some of the key challenges.

Installation of LV monitoring[47] and smart meters is providing data to help us understand how our network is configured, how it performs, and improving our visibility to enable us to better correlate local generation with customer demand. LV fault management devices are being deployed to improve our response to LV faults and reduce CI/CMLs.

Data analytics is being undertaken to understand how we can make best use of available data and drawn from existing knowledge. We are already successfully using robust data science techniques to fill key information and data gaps.

Innovation projects are looking at new tools and technologies that can be deployed to support longer term visibility of, and interactivity with, the LV network.

We have a Connectivity Model under development which is building up the electrical connectivity of our network across all voltage levels, including LV. In parallel we are building up a customer model which will be overlaid such that we will have a picture of where and how customers are connected along different LV

[47] ED2 LV Monitoring Engineering Justification Paper (EJP) provides further details.

feeders. Our ED1 IT Project 'Connectivity+' is supporting the development of this capability and will continue to be augmented with our enhanced ED2 IT project, 'Connectivity++'.

Using the information above we will provide anticipative information and investment in network reinforcement and flexible services as appropriate to minimise delays and barriers LCT uptake.

The LV Strategy gives context and impetus to these challenges and opportunities, and sets-out actions that we will take going forward to continue to address these challenges and build upon the work that is already being done.

4. OUR STRATEGIC APPROACH

To develop an LV Strategy and ensure it is can be effectively implemented in the business, we need a sound understanding of the following:

- the **outcome** we are seeking to achieve;
- **what** key actions we must take;
- **why** we must take these actions; and
- **how** we intend to enable and deliver these actions.

4.1. THE OUTCOME

There are three LV Strategic Outcomes for the LV network. Referring to

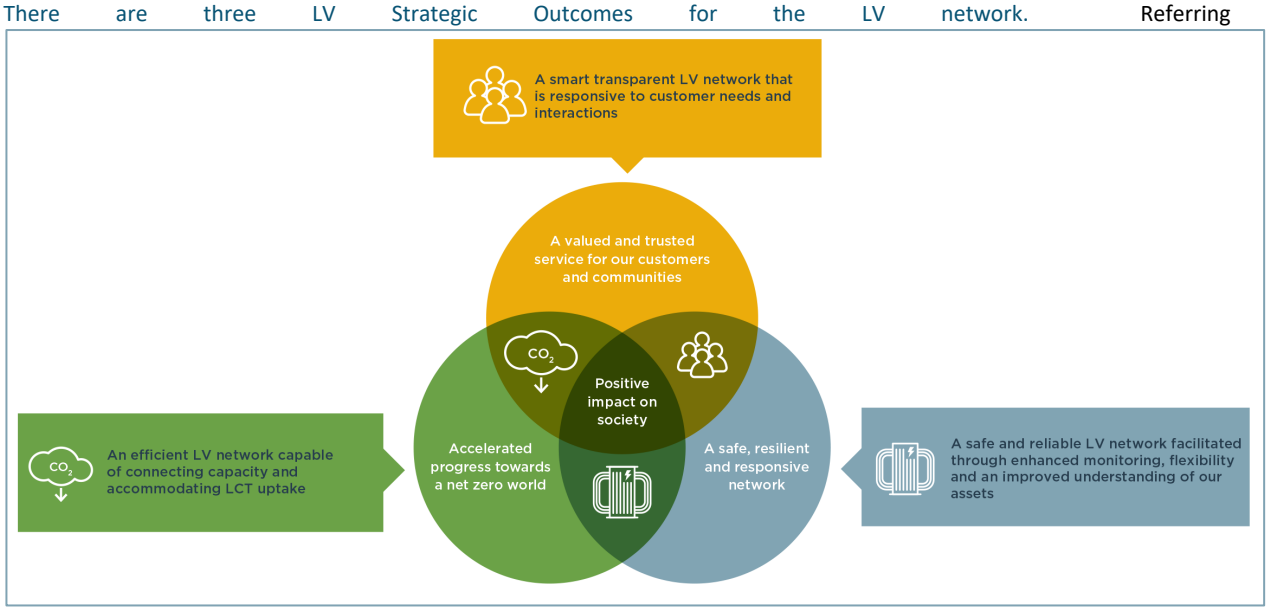
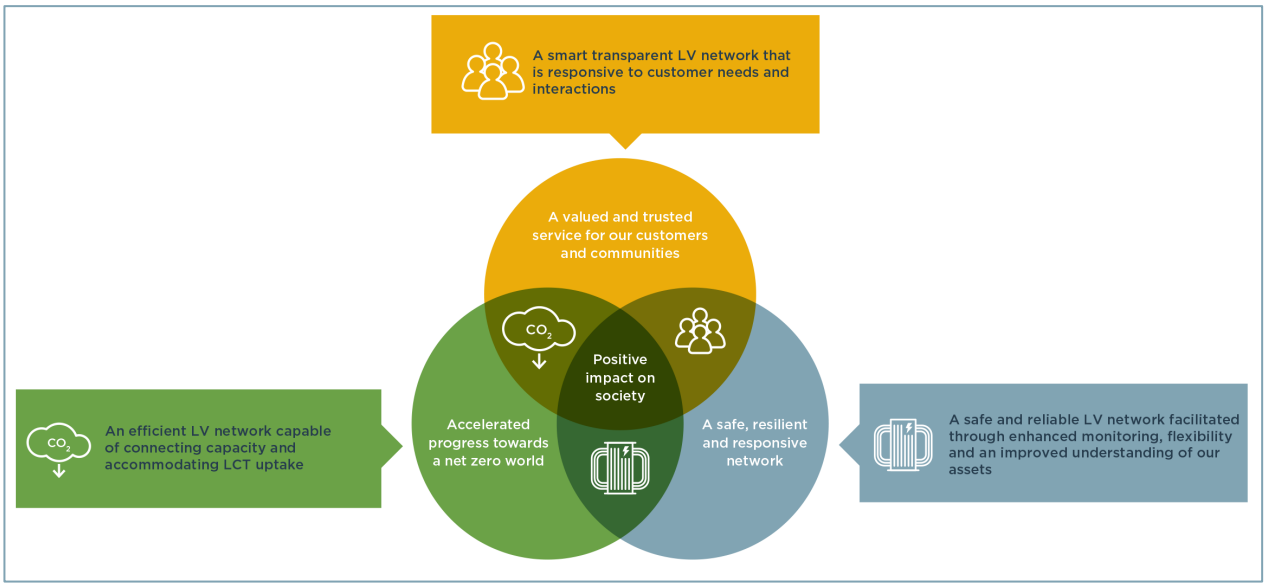


Figure 29 – Interpretation of our Strategic Outcomes for our LV Network

- In Green we have a customer-focused outcome; centred on enabling a smart, transparent network with which customers are able to easily and usefully interact, and which is responsive to their needs.
- In Blue, our asset-related outcome is focused on the LV network itself and the assets; the outcome is to provide a safe and reliable network which we can achieve through enhanced monitoring, flexible operation, and a better understanding of our assets.
- In Orange, our load-related outcome is focused on the provision of an efficient network; one which can connect capacity and accommodate LCT uptake.

These specific LV Strategic Outcomes align with the overall Strategic Outcomes for the SSEN Distribution Business which form the basis of our ED2 Business Plan, as shown



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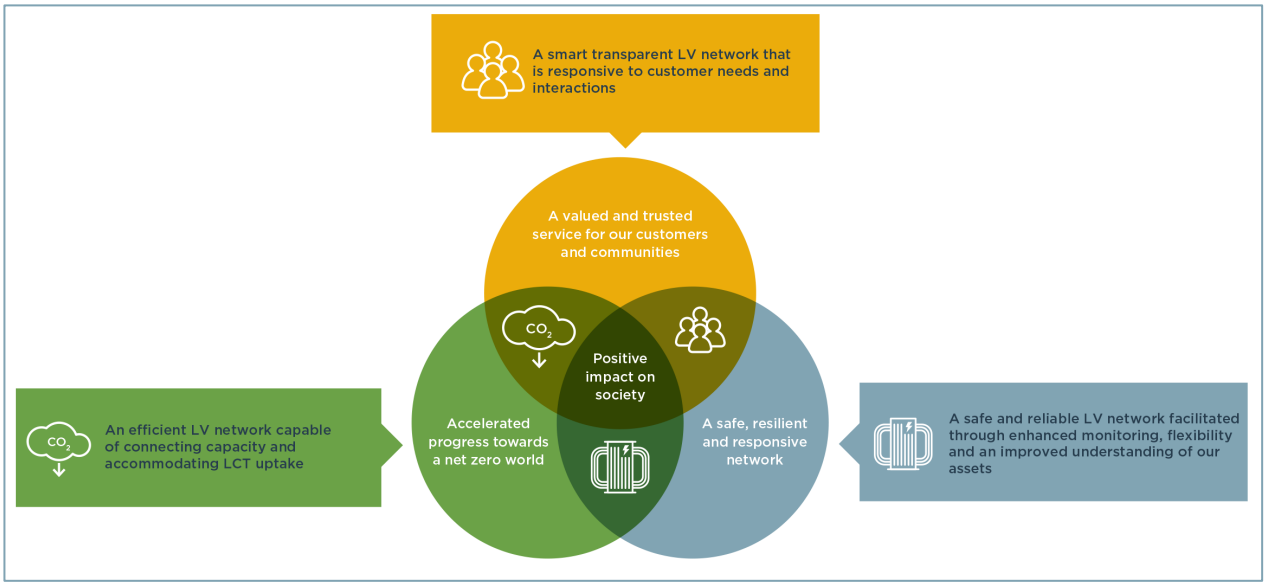


Figure 28 – Interpretation of our Strategic Outcomes for our LV Network

The following sections outline the What, Why and How for each of the LV Strategic Outcomes. We have ensured actions are aligned across the three areas such that efficiencies can be made, and the delivery of the LV Strategy will support and synergise with other key business strategies and the ED2 business plan.

4.2. IMPROVED UNDERSTANDING OF OUR LV ASSETS

A safe and reliable LV network facilitated through enhanced monitoring, flexibility and improved understanding of our assets

WHAT must we do to improve understanding of our LV assets?	WHY is this action required?	HOW can we achieve this?	Reference for delivery ED2 Business Plan
Understand the health of our assets	To ensure we invest when necessary, align with load related drivers, and ultimately balance network cost against customer cost and broader societal cost	▪ Digitalise our asset management systems as per our Digital Strategy to enable faster, more coordinated data access and overall data reliability.	C4 -Safe Resilient Responsive Network / Insights & Automation + OT
		▪ Ensure our maintenance and inspection plans follow asset management policy on inspection criteria.	CV30 – Inspections CV31 – Repair & Maintenance
		▪ Ensure information is fed back into asset management systems and records are kept up to date.	CV17 – Rising Laterals & Mains
Understand and address legacy issues with faults – reduce the level of faults on the LV network.	To avoid customer disruption, improve network reliability, improve fault restoration performance, and improve customer and stakeholder trust	▪ Continue to deploy LV monitoring and fault management devices (e.g., Bidoyng) in areas with high incidence of faults. Pro-actively manage legacy issues in known problem areas as well as analysis of fault patterns.	CV11 - LV monitoring
		▪ Deploy LV monitoring devices on all new substations as standard from ED2.	
		▪ Develop tools to analyse data from monitoring devices and feed this into Outage Management System (OMS) and maintenance plans.	Non-Load Strategy Annex: CV30 – Inspections; CV31 - Repairs and Maintenance; CV11 – Progress to Net Zero / Platform; C4 – Positive impact on Society / Insights & Automation
		▪ Map information on problematic assets to load and non-load investment plans to support cost-benefit analysis (CBA) and to ensure that we are investing efficiently.	CV7a – Asset Replacement
Understand the impact of providing flexibility services on the health of our LV assets	To enable us to use flexibility services to resolve capacity issues while ensuring it doesn't adversely impact the health of existing assets	▪ Test and stimulate the flexibility services market at LV level	CV4 – Progress to Net Zero / Insights & Automation C4 – Progress to Net Zero / Flexibility Markets (Platform)
Understand and address asset failures due to specific characteristics **(e.g. LV Consac cable) or circumstances (e.g. excessive tree growth)**	To enable us to form and implement effective strategies to address these items (e.g. replacement programme for Consac cable, tree cutting strategy), ensuring we align with other ongoing work (such as I&M activity) and making efficiencies where possible	▪ Utilise LV Monitoring and other operational technologies to improve fault finding and digitise reporting processes.	C7 – STEPM (Non-op) C4 – Positive impact on Society – Insights & Automation C4 - Safe Resilient Responsive Network / Platform
		▪ Ensure fault and remedial action records are logged centrally in our asset management systems.	Non-Load Strategy Annex CV26 - Faults
		▪ Perform root-cause analysis (where practicable) or data analytics on faults to better understand the extent of issues on our network and implement efficient solutions.	C4 – Positive impact on Society (Insights & Automation); C4 - Safe Resilient Responsive Network / Platform
Ensure we align with our Losses Strategy when making asset investment decisions	The Losses Strategy has been developed to optimise losses and suggests minimum requirements for assets to meet this objective	▪ Ensure Losses Strategy is followed when undertaking LV asset replacement work.	C4 – Positive impact on Society – Insights & Automation C4 - Safe Resilient Responsive Network / Platform. The direct losses costs sit in table CV21 and our approach is outlined in our Environmental Action Plan. A 15

Table 29 – Actions for improving understanding

Table 29 provides details of the actions we will take to develop an improved understanding of our LV assets and LV network.

Understanding the health of our existing LV assets, taking action to diagnose asset failures and address legacy issues will improve our overall LV network reliability through better coordination of remedial and investment actions. Aligning with the Losses Strategy ensures any actions and investments we do make will adhere to losses related policy to improve network performance and help deliver on our Business Carbon Footprint and our sustainability goals. This approach will stand us in good stead to manage future challenges as they arise. A key feature of the ED2 business plan is the implementation and roll out of LV flexibility services, as part of our transition to DSO, and so it is vital that we test and stimulate this marketplace to understand the impact that flexible operation could have on the health of our LV assets.

To enable us to achieve this, we must ensure our processes and systems for collecting and recording data and information is digitalised in line with our Digital Strategy. It should be centrally stored, easily accessible and kept up to date. In doing so, we will support and enhance several other business functions and activities, including:

- Facilitate LV monitoring roll out by providing information to help optimise device location installation.
- Support network analysis with improved data, tools, and models to support future maintenance plans and outage planning.
- Enable root cause analysis to be performed on faults and solutions to be implemented more effectively.
- Feed into investment planning, supporting efficient investment through improved understanding and knowledge of asset health.
- Map the amount of flexibility active on each network to model and predict half hourly price market-based demand peaks and understand Flexibility Service contracting potential; and
- Understand tariff distribution.

4.3. AN EFFICIENT LV NETWORK TO SUPPORT LCT UPTAKE

An efficient LV Network capable of connecting capacity and accommodating LCT uptake

WHAT actions will allow us to ensure adequate capacity is available?	WHY is this action required?	HOW can we achieve this?	Reference for delivery ED2 Business Plan
Understand the network and where our customers are connected	To enable us to more accurately forecast demands and future LCT uptake on a more granular level, and consequently ensure we are investing appropriately to manage this and proactively providing capacity.	▪ Continue to build the network Connectivity Model in Electric Office, including the LV network.	
		▪ Roll-out monitoring on LV assets loaded to 80% or more to better understand capacity constraints and patterns of growing demand. Also roll out monitoring in areas of generally poor LV network visibility.	CV11
		▪ Use Smart Meter data to obtain an improved and more accurate view of customer connectivity and demand profile and refine load forecasts and identify locations which will benefit from LV monitors	C4 – Positive impact on Society / Insights & Automation
		▪ Use Smart Meter data to understand the 'Flexibility index' of each LV network and its resulting response to price signals.	C4 – Progress to Net Zero / Flexibility Markets (Platform)
Understand the operational state of the network and the running arrangements	To verify the true state of the network under normal operating conditions and ensure we are making investment decisions taking full consideration of abnormal running arrangements (e.g. back-feed via link-box)	▪ Capitalise on planned maintenance and inspection activity by gathering more detailed information on the operational state of the network where this isn't the primary activity (e.g. link box configuration)	
		▪ Ensure information is routinely reported back to the Connectivity Model, and the Control room.	
		▪ Ensure any network reconfiguration actions are reported and logged centrally.	
Address looped services that may impact our ability to provide customers with capacity	To ensure we remove any barriers to customer LCT uptake	▪ Respond promptly to customer requirements for larger fuses to allow them to connect LCTs in a timely manner.	Load Annex
		▪ Physical inspections to proactively address known issues with capacity limitation on domestic services (e.g. looped services)	Load Strategy Annex
		▪ Undertake the work required to upgrade domestic service capacity from 60A to 100 A where and when needed. And to implement the appropriate supporting commercial policy to ensure we do not deter or hinder LCT uptake for any individual customers.	Connections Strategy Annex
Seek to understand how the behaviour of our customers is changing, and what factors are contributing to these changes	To allow us to map what we know about where customers are connected to the LV network, and how we expect their behaviour to change, ultimately providing better forecasts.	▪ Build up picture of customer activity through collaboration with EV retailers, EV charge point installers, heat pump installers, flexibility aggregators etc.	
		▪ Work in a Whole System way with local authorities, including gathering information from their strategic plans.	Whole System Annex / work force planning
		▪ Continue to collaborate with the ENA and other UK DNOs on industry-wide knowledge and information sharing on customer behaviour and network requirements e.g., the ENA Embedded Capacity Register.	C4 – Trusted and Valued service / Customers & Ecosystem

Table 30 – Actions to ensure LCT uptake for net-zero

Table 30 provides details of the actions we will take to ensure that our LV network is able to meet the net-zero challenge by supporting the significant uptake in customer LCT.

For us to offer network capacity to our customers to enable them to connect LCTs (such as EVs, solar PV and/or heat pumps), we must first understand where we do and don't have spare capacity on the existing network. A critical aspect of this strategy is the plan to collect more information on, and therefore gain a better understanding of, our LV network and customer connectivity, including:

- Where our LV customers are connected.
- How the LV network is configured; and
- Where constraints are likely to appear in future on the LV network.

On the customer side, our understanding of our customers can be improved by working in a Whole System way with our stakeholders, including collecting and analysing additional data and information – such as applications for EV charger grants or engaging with Local Authorities on their plans. We can also build a fuller and more accurate picture of customer behaviour by implementing sophisticated data analytics tools. By drawing on, and analysing, limited information from multiple sources – and combining this with broader information on area demographics and other socio-economic factors, we can greatly improve our planning and decision-making to ensure we meet customer needs, when and where it is required.

On the network side, a combination of addressing legacy issues (i.e., looped services), deploying LV flexibility services and building a clear picture of our network connectivity and operational state through the Network Connectivity model (and eventually the Digital Twin in an LV control room) will position us to be able to respond to customer needs efficiently and undertake investment cost-effectively.

4.4. A SMART AND INTERACTIVE LV NETWORK

A smart transparent LV network that is responsive to customer needs and interactions

Table 31 – Actions for a smart and interactive LV network

WHAT must we do to deliver a smart, transparent network?	WHY is this action required?	HOW can we achieve this?	Reference for delivery ED2 Business Plan
Develop the capability to operate and manage the LV network in real-time	The LV network will change drastically in the coming years and will require a more proactive approach to operation and control	• Create digital twin of LV network based on the Connectivity Model to use in LV control room/control system.	C4 – Progress to Net Zero C11 – Progress to Net Zero
		• Roll-out monitoring and communications infrastructure to collect real-time data from across the LV network.	Digital Investment Plan CV11
		• Expand and improve on LV automation to develop a more responsive network overall.	C4 - Digitalisation Strategy
		• Leverage the use and value of LV Monitoring, and other Operational Technology (OT) data by developing data analytics tools to process and understand data that is collected.	C4 - Digitalisation Strategy
Undertake actions necessary to enable DSO functionality at LV, taking guidance from our DSO Strategy	The transition to DSO will allow us to accommodate significant electrification of heat and transport – using our existing asset base efficiently and in a way that enables us to serve our customers flexibly	• Roll out monitoring and communications infrastructure in line with our DSO Strategy to collect real-time data and enable DSO functions e.g. flexibility.	C4 – Progress to Net Zero / Flexibility Markets (Platform)
		• Use learnings from other DSOs on how LV Flexibility services can be procured and offered.	DSO Annex 15, Appendix F – 'Delivering Value Through Flexibility'
		• Proactively recruit flexibility services across all potentially at-risk networks both directly in the case of large customers and through intermediaries such as suppliers and aggregators.	
		• Build up understanding of customer readiness for flexibility services and LCT connection status	
		• Co-ordinate our LV flexibility services management with higher voltage requirements and those of the ESO.	
Align with our Digitalisation Strategy when considering roll out of OT and IT	Operational Technology (OT) and Information Technology (IT) are critical to improving visibility of our network and enabling more real-time control functionality through data exchange. Our Digitalisation Strategy [1] outlines the ways in which we are working to enable this.	• Roll out monitoring and communications infrastructure in line with our Digitalisation Strategy to enable the collection real-time data and enable control functionality.	Digital Investment Plan CV11

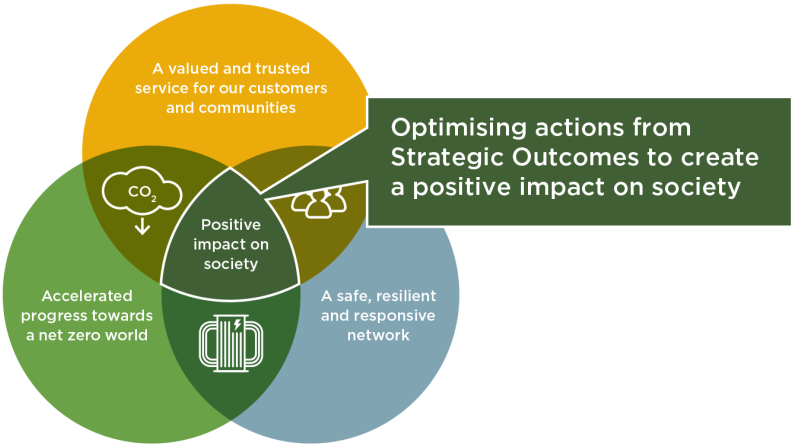
Table 31 provides details of the actions we will take to ensure a smart and interactive LV network that is responsive to customer needs and interactions.

It is crucial that we provide a smart and transparent network that customers can interact with, and that is responsive to their needs. This will be best enabled by digitalisation and our transition to DSO. Linking into our Strategic Outcomes to provide a safe and reliable network with capacity to connect LCTs, this outcome will see us provide the infrastructure and systems to empower our customers with more choice and freedom to participate in energy markets and maximise the value they gain from connecting LCTs.

Our development of a network Digital Twin and an LV control room will improve network responsiveness and allow for increasing real-time controllability as LCT uptake increases, flexibility services become more pronounced and a full transition to DSO at LV can be realised.

4.5. A POSITIVE IMPACT ON SOCIETY

Bringing together the key actions set out to deliver on our LV Strategic Outcomes, we will provide a smart, reliable, accommodating and customer-friendly network. We will work towards having a clear picture of the existing network and its future requirements to ensure we optimise investment in our LV network while minimising the frequency of interventions. Achieving this will yield enormous efficiencies in time and cost in the long run, while also ensuring we minimise customer disruptions as well as our impact on the environment.



We are also aware that a positive impact on society includes full and fair consideration of customers in vulnerable situations. Accelerated progress towards a net zero world must be part of a just transition – ensuring we accommodate the needs of existing and well as new consumers.

The actions set out in this strategy present a real opportunity to improve coordination of our investment plans and ensure our network does not become a barrier to customers who choose to adopt LCTs. This will be supported by an improved understanding of our network and our assets, through a combination of proactive monitoring and data analytics. Mapping to information collected about evolving customer behaviour and other external influences will ultimately allow us to take a much clearer, more holistic view of the likely network and customer needs in different areas. It will also help us to identify the optimal time and scale of investment to ensure we invest efficiently, effectively reducing costs and customer disruption, while providing adequate capacity and network reliability as it is needed. Working with wider stakeholders, such as gas, water and telecoms industries to streamline investment plans will also avoid duplication of customer disruption and bring about cost efficiencies across the different sectors.

By optimising delivery of our three LV Strategic Outcomes – our asset-based outcome to ensure a safe and reliable network; our load-based outcome to deliver an efficient network to connect capacity; and our customer-focused outcome to provide a smart, interactive network – we can also ensure we create a positive impact on society.

5.BUSINESS-WIDE BENEFITS

It is very important to identify areas of synergy and cross-over where efficiencies can be made or benefits from an action can be maximised. An example of this relates to improving data, information and understanding of the network. Every business area working on, and with, the LV network will benefit from additional and enhanced data and information going forward. We believe that it is critical to every area of our electricity distribution business.

BUSINESS AREA	KEY BUSINESS OBJECTIVES	DATA REQUIREMENTS
OPERATIONS	Timely repair of faults	• Network connectivity • Fault location • Feeder location and fault history • Number of customers connected
SAFETY	Safe project execution	• Network connectivity • Fault location • Feeder location and fault history • Number of customers connected
CONNECTIONS	Efficient design of connections	• Local network connectivity, including looped services • Local network loading / available capacity • Local Network Plans
PERFORMANCE	Customer satisfaction and opportunities for continued improvement	• CI/CML • Fault and maintenance records • Asset information e.g. age, condition • Losses Strategy
ASSET MANAGEMENT	Effective management of asset classes and preventative actions	• Health Index • Maintenance records • CI/CML • Asset Strategy
ED2	Robust planning and invest-ment decision making	• Demand (max, cyclic) of feeders and transformers • Ratings of feeders and transformers • Network connectivity • Asset condition and performance • Uptake and connection of LCTs, including location • Local Network Plans • Connected generation/DER assets
DSO	Enable market participation in flexibility and other services	• Demand (max, cyclic) of feeders and transformers • Thermal and voltage issues • Customer capability to participate in flexibility market • DSO Strategy • Connected generation/DER assets
FUTURE NETWORKS	Develop scenarios and tools for future planning across all business areas	• Network connectivity • Uptake and connection of LCTs, including location • Flexibility service options • Digital Strategy • Connected generation/DER assets

Figure 29 - key business objectives and the data that is important for each business area

Figure 30 highlights the key business objectives and the data that is important for each business area.

Several of the actions proposed to deliver on our LV Strategic Outcomes will ensure data is collected, cleansed and readily available to the different business areas. This will in turn provide widespread improvements in meeting our business objectives, and ultimately in delivering our LV Strategic Outcomes.

Improvements in understanding of network connectivity, and having access to more and better data, will bring the following benefits to the different business areas:

i. Operational staff need to know exactly what work they are undertaking and on what asset, where the asset(s) is located and what it is connected to. They must also have the right tools available to ensure efficient working practice and minimal delays. Greater understanding of the network will enable a more robust project planning process overall and improve fault finding activities.

ii. A more robust planning process will result in fewer incidents and a better health and safety record for SSEN.

iii. Our Connections activity will benefit from increased visibility of the local network, its capacity to accommodate additional generation and/or demand and any other plans for the area such that they can design an efficient connection. In future it will be helpful to know where EV chargers are being connected (it would also be useful to see how well this match with the EV Strategy and the DFES analysis on an ongoing basis).

iv. Improvements in procedures across operations, safety and connections will result in improved performance. Better fault and maintenance records could form part of this and feed into the operations and safety business areas. Further improvements in operations and performance through better planning and procedures can also be achieved by logging information centrally and making it available for future projects.

v. Asset management of LV assets will be better coordinated with improved visibility of asset age, condition, maintenance records and performance data. Assets are currently managed in our asset management system, fed by inspection data from our operational staff. It is critical that data in the asset management system is consistent with that being used in other business areas.

vi. The ED2 business plan is being prepared using data and data analytics tools currently available within the business. More granular information about the LV network will allow us to make more informed and justifiable investments across their LV asset portfolio.

vii. The DSO transition cannot be achieved without data availability and the capability to use and exchange this data. This will largely be facilitated by the Digital Strategy and the DSO Strategy, but the importance of DSO on the LV network is expected to be significant and so this must be enabled through the provision of data and communication systems.

viii. Data and an understanding of network connectivity are critical to the work being done by our innovation team. Recognising that it will take significant time and effort to achieve complete coverage and visibility of the LV network, it is important that we maximise the value of the information we do have. By developing robust data analytics tools, we will improve our understanding of the network and use this information to support efficient decision making.

Collectively, the key datasets required by the business areas can be summarised as follows.

- Network connectivity
- Fault location
- Feeder location
- Number of customers connected
- Connected generation assets
- Fault and maintenance records
- Network loading/capacity
- Maximum demand
- Asset health information
- Asset ratings information
- Customer behaviour

Mapping the required datasets listed above to the actions proposed to meet our LV Strategic Outcomes shows that almost universal business-wide benefits (in this case specifically relating to improving network visibility and data availability) can be achieved through focused effort in the delivery of a few of these actions. This is shown in Table 32.

Table 32 – Mapping the data sets

DATASET	CORRESPONDING ACTIONS	HOW WE WILL DELIVER ON THESE ACTIONS
NETWORK CONNECTIVITY	• Understand the network and where our customers are connected • Understand the operational state of the network and the running arrangements	• Continue to build the network Connectivity Model in Electric Office, including the LV network.
		• Roll-out monitoring on LV assets loaded to 80% or more to better understand capacity constraints and patterns of growing demand. Also roll out monitoring in areas of generally poor LV network visibility.
		• Use Smart Meter data to obtain an improved and more accurate view of customer connectivity, and eventually demand profiles.
FEEDER LOCATION		• Capitalise on planned maintenance and inspection activity by gathering more detailed information on the operational state of the network – e.g. link box configuration – where this isn't the primary activity.
NUMBER OF CUSTOMERS CONNECTED		• Ensure any network reconfiguration actions are reported and logged centrally
		• Build up understanding of customer readiness for flexibility services and LCT connection status
FAULT & MAINTENANCE RECORDS	• Understand the health of our assets • Understand and address legacy issues with faults • Understand and address asset failures due to specific characteristics or circumstances	• Ensure our maintenance and inspection is following asset management policies which should outline inspection criteria for health information
		• Continue to deploy LV monitoring and fault management devices (e.g., Bidoyng's) on the LV network in areas with high incidence of faults and to manage legacy issues; do this pro-actively in known problem areas as well as re-actively as faults occur and fault patterns arise. • Deploy LV monitoring devices on all new substations as standard from ED2.
		• Develop tools to analyse data from monitoring devices and feed this into Outage Management System (OMS) and maintenance plans.
ASSET HEALTH INFORMATION		• Improve fault finding and reporting processes • Data based health and pre-fault detection
FAULT LOCATION		• Perform root-cause analysis (where practicable) or data analytics on faults to better understand the extent of issues on our network, and implement efficient solutions
ASSET INFORMATION	• Seek to understand how the behaviour of our consumers is changing, and what factors are contributing to these changes • Understand the operational state of the network and the running arrangements • Develop the capability to operate and manage the LV network in real-time	• Build up picture of customer activity through collaboration with EV retailers, EV charge point installers, heat pump installers, flexibility aggregators etc.
		• Work in a Whole System way with local authorities, including gathering information from their strategic plans.
		• Roll out monitoring and communications infrastructure to collect real-time data and enable DSO functions e.g. flexibility
		• Maximising the use and value of LV monitoring (and other OT) data by developing tools to process data that is collected

5.1. ENERGY DATA TASKFORCE

June 2020 Ofgem published an Open Letter: 'Review and next steps: RIIO digitalisation strategies'. The letter provides feedback on the RIIO Digitalisation Strategies which have been developed by industry. In this letter, Ofgem continues to strongly support the recommendations of the Energy Data Taskforce and confirms that it intends to introduce a licence condition requiring network companies to comply with 'Data Best Practice' guidance.

One of the headline recommendations of the Energy Data Taskforce is the principle of Presumed Open which is now one of the 12 core principles. Presumed Open actively encourages open data and data sharing which will enable decarbonisation, stimulate innovation, and help support the growing number of UK based digital energy innovators.

6. ENABLING THE STRATEGY

The previous sections have set out the key actions we must undertake to deliver on the Strategic Outcomes set for the LV network. This section focuses on how we can best enable the required actions.

6.1. Asset Health Management

Better understanding the health (condition) of our LV network assets is one of the key actions we must seek to deliver to meet our Strategic Outcomes. The impact of the changing operational philosophy i.e., bi-directional power flows and different cyclic demand patterns, on asset health must be considered.

The LV network is complex and a substantial length of time and a significant effort to gather accurate health information on all our assets will be required. Using other tools at our disposal, such as data analytics, will provide a good degree of confidence in what we know about the assets, which we can use to make decisions, as we work towards building up our database.

There are already systems in place where asset health information is logged. The focus therefore should be on:

- Improving the accuracy and range of the asset health information (age, condition, etc) in our databases as well as working towards correcting any errors such that the information can be relied upon across the business. **This would provide reliable data for multiple business functions, including load and non-load related investment planning.**
- Implementing robust maintenance and inspection procedures that extend beyond the current remit could be an efficient means of collecting more and better data on asset condition. **This will support improvement of asset health databases and maximise value of maintenance and inspection activities.**
- Digitalising, standardising central logging and reporting of all information is critical to ensure our databases are always up to date. **This will ensure the whole business always has access to the latest asset information.**
- Training and upskilling maintenance and inspection teams to empower them to undertake a range of activities, such as installing LV monitors. **This could deliver efficiencies across operational activities.**
- Develop tools to process and analyse data. **This information could inform future maintenance and inspection plans, feed into the OMS or support investment decision making.**

6.1.1. ASSET MANAGEMENT POLICIES

We have a Strategic Asset Management Plan (SAMP) specifically for our distribution networks which sets out a risk framework. The SAMP and the LV Strategy actions must align on issues relating to asset health and asset management.

We also have some specific strategies relating to LV assets, such as link boxes and service cut-outs. Our proposed LV Strategy actions seek to complement these strategies, particularly as these will help us deliver on our strategic objectives.

When assets are being replaced, this will be done in accordance with the Losses Strategy. This includes minimum sizing for LV cables (i.e. large section e.g. 300mm^2) and minimum ratings for transformers. Other loss reduction opportunities should also be considered on a case-by-case basis e.g. phase balancing.

6.1.2. FAULTS

Improving how we detect, locate and remedy faults, including legacy fault issues, on our LV network will have a significant impact on the performance of our network, the service we provide to our customers and the investment decisions we make.

Presently we face several challenges in relation to fault detection, including:

- Our LV network is not extensively monitored and so often we must wait for a customer to advise that they are off supply to be made aware of a fault. We have commenced the application of smart meter alerts to manage network outages. This process will increase with the increased penetration of Smart Meters on our network.
- The network connectivity information supplied to our operational teams can be inaccurate and so time must be spent locating the right circuit, asset, or customers to isolate.
- The nature of the fault is not always known, and so operational teams may not be equipped with the appropriate tools to undertake the necessary remedial actions.
- Remedial actions taken on a fault are not always recorded centrally so fault history on circuits is not always complete.
- Root cause analysis is not conducted due to missing or incomplete fault histories and repeat issues are not escalated as a result.

We have known legacy issues on our LV network, and these must be addressed as a priority as per our Strategic Asset Management Plan. This can be enabled by implementing a consistent approach to our fault-finding activities.

- More extensive deployment of our fault management operational technologies and LV monitoring should be rolled out on the LV network: proactively in known problem areas; reactively as faults occur; and more generally in areas of poor visibility. **This will speed up fault detection times, and ultimately restoration times. This could also help to better understand the operational health of assets which will support us in avoiding/preventing failures.**
- Maintenance and inspection activities should be coordinated with a focus on addressing priority issues in accordance with monetised risk. We should also seek to optimise the scope and scale of interventions where possible to ensure efficiencies (i.e., across load, non-load and fault response activities). **This will reduce recurring issues and minimise customer disruption.**

- Clear instructions on what interventions/solutions to deploy in specific circumstances should be provided. **This will allow operational teams to equip themselves with the right tools and minimise delays in restoration times.**

- A standard, digitalised reporting procedure should be rolled out where pro-forma information is collected and reported centrally following the completion of any fault-finding activity. **This will improve data collection which will feed into wider databases for asset management etc.**

- Fault histories, built up through successful implementation of the previous actions, should be made available to operational teams. **This will support the operational teams in their reporting.**

- An escalation procedure (root cause analysis, investment etc) should be put in place to effectively detect and action recurring issues. **This will ensure issues are dealt with efficiently and in order of priority.**

These enabling actions will bring about long-term benefits by incrementally building up our knowledge and data on our assets and faults, so there needs to be options available such that we can manage faults in the short to medium term.

The 'Fault Discovery' proof of concept is trialling the use of prediction analytics and machine learning to "*highlight areas of the network or individual components that may be subject to failure in the short/medium term to help build future investment plans*". This programme uses data analytics to support in the build-up of these records by identifying susceptible or problematic areas, or assets, thus allowing focussed effort in particular areas to address legacy and other issues.

Pre-Fault Analysis is a proof of concept explored through Network Investment Allowance (NIA) funding, in ED1, by SSEN's Future Networks Team. SYNAPS 2 NIA is set to complete in 2022. At LV level the aim of the program is to capture data from source and integrate within SSEN's existing IT systems. This will facilitate seamless management generating efficiencies through reduction of occurrences of Customer Interruptions and Customer Minutes lost. The data will also be housed in the companies Azure platform allowing for SSEN's Data Strategy to deliver its programme of data quality management enabling our data to drive efficiencies and support best practice when operating our Network as a whole.

6.2. NETWORK CONNECTIVITY

Understanding how our LV network is connected is of critical importance as we move further through the energy transition.

If we are to provide capacity to our customers on an ongoing basis, we must always know where capacity is available and where the network is constrained.

It is therefore crucial that we not only improve our understanding of where our customers are connected and how the network is configured, but we also ensure this information is accessible and of sufficient accuracy.

6.2.1. CONNECTIVITY MODEL

Our Connectivity Model is an ongoing initiative which requires extensive collection of additional data and information on the Extra-High Voltage (EHV), HV and LV distribution networks.

The model is being built manually, and so far, the focus has been on the HV network . Full HV connectivity is due to complete in 2021[48].

The LV network presents unique challenges in this respect, particularly as we do not currently have full oversight of the LV network. It will take time and resources to build up this visibility. We can enable and accelerate this process by:

- Committing resources to continue to collect information and build up the Connectivity Model at LV. **This should accelerate progress and demonstrate the importance of this initiative.**
- Capitalise on maintenance and inspection activity to gather detailed information on the operational state of the LV network i.e. the status of link boxes etc, and/or install monitoring equipment (where this is not the primary activity already). **This will maximise value of maintenance and inspection activities and bring overall efficiencies in data collection.**
- Ensure any operational activity carried out on the LV network that involves network reconfiguration is reported and logged centrally. **This will ensure the latest network connectivity information is always readily available.**
- Support delivery of Connectivity++ IT Investment. The primary focus of this project is to link customer information to our connectivity model.

6.2.2. MONITORING AND DATA

Pivotal to the development and success of the Connectivity Model, and eventually the LV network digital twin, is the availability of data and the provision of visibility through this data. Data is required to build up our picture of the network, and to maintain visibility on an ongoing basis. Over time, historical records and profiles could also be used to look at patterns of activity and behaviour to detect and diagnose issues.

Fundamentally, we will improve our visibility of the LV network through:

- Roll out of monitoring devices strategically, focusing in areas of generally poor visibility, areas that are known to be constrained and areas where we expect high uptake of LCTs. **This will offer a level of coverage across all areas of network, with more extensive coverage of areas where we anticipate high levels of activity or specific issues to arise . We are expecting to install over 21,000 LV monitors in ED2, and thanks to recent funding as part of the Green Recovery this will be supported by around 1,700 monitors being installed in ED1, bolstering the circa 700 already procured. By end of ED2 this will equate to 20% of our LV network being monitored.**
- Develop data analytic tools that allow us to process data into useful information that can be actioned as appropriate. **This will allow us to leverage the data we collect for decision making, and also infer information about areas with limited coverage using sophisticated data analytics** (see Section 6.5).

6.2.3. CONNECTED CUSTOMERS

48 Approximately 40% complete as at June 2021.

Customer connectivity is another key factor in building our Connectivity Model. SSEN has information on its customers, mostly a combination of Geographic Information System (GIS) data and Meter Point Administration Numbers (MPAN). Combining this with smart meter data will drastically improve the granularity of visibility we have on where our customers are connected. It is therefore imperative that SSEN:

- Supports the continued roll out of smart meters to reach 95% coverage by 2024 in line with government targets. **This will ensure we meet government targets and can rapidly benefit from increased visibility at customer level which is something that has never been available previously.**

- Work with industry, including BEIS, Ofgem and other network companies, and consumers to break stigma of smart meters and privacy concerns. **This will ensure we are actively engaged with customers and industry to advocate a mutually beneficial position regarding data privacy.**

- Provide necessary infrastructure (liaising with the telecoms industry where required) to capitalise on the collection of data. **This will enable data to be collected and fully utilised for the benefit of SSEN and its customers** (see Section 6.3.6).

The roll-out of smart meters presents a huge opportunity for us as the devices can be configured to collect data in numerous ways. We must specify what data is required to meet our different business objectives e.g. half hourly data should be collected to inform on LV circuit capacity, daily profile data could be used to assess customer behaviour, annual data could be used to get a more accurate view of maximum demand. With these activities comes the question of value to customers versus the cost of providing the necessary infrastructure and data processing capability and storage capacity.

6.3. DSO AND DIGITALISATION

The transition to DSO and the Digitalisation Strategy are complementary. The DSO function cannot be fully implemented without an appropriate digital infrastructure.

6.3.1. DSO

The intention is to overlay the Connectivity Model with a customer model which is currently being populated using GIS data, although smart meter data will be leveraged when there is more extensive coverage. Eventually, the Connectivity Model will allow us to develop a digital twin of the whole network from LV to 132kV and this model will be accessible in the ADMS/control room. From here, real-time data from LV monitors, smart meters and other OT can be used to show the real time status of the LV network which will become an increasingly important function to support our DSO activities. This is being supported by the ADMS+ IT project in ED2.

6.3.2. LV FLEXIBILTY

With the uptake of LCTs and the electrification of demand, comes the opportunity for greater levels of customer involvement in the day-to-day safe and efficient operation of our LV network.

Flexibility services are expected to play a huge role in the future operation of our LV network. Flexibility services can take many forms depending on what network issue is being resolved by the service e.g. thermal overload, voltage, fault level. At LV, it is expected that the most prolific flexibility service will be related to

thermal overloads and the needs to manage power flows and consumption at specific times. These services could include smart EV charging or time-of use tariffs, and would involve participation from customers, suppliers and possibly aggregators.

Using flexibility on the LV network provides a cost-effective approach to managing customer demand, as compared to asset replacement.

The Load Managed Area (LMA) in SHEPD where c. 87,000 customers have controllable heating load is a good example of how flexibility can be used to defer network reinforcement through the management of consumption. Since the 1980s, SSEN has been able to schedule heating demand to diversify peak load during the night. The radio tele switching used to control the LMA is being decommissioned by the BBC and so SSEN is implementing alternative arrangements to ensure the same level of peak load diversification can be achieved. A longer-term strategy to lift LMA switching restrictions – where the (customer) benefits of so doing, outweigh the (customer) costs – is being progressed alongside short-term measures to maintain safe and reliable operation of the network.

'LV flexibility where customers opt-in is still a relatively novel concept and there are likely still several challenges and issues to work through. SSEN is exploring this through innovation LV Flexibility. In collaboration with National Grid Electricity System Operator (ESO), our 4D Heat project has explored whether controlled electrified residential heating in Scotland can reduce the curtailment of renewable generation, without adversely impacting the LV distribution network. Also, SSEN with Octopus Energy, Ohme and the ESO have teamed up to conduct the UK's largest ever home energy flexibility study. CrowdFlex, will analyse 25,000 household energy use patterns to demonstrate how households might change their behaviour and charge electric vehicles, heat pumps and home batteries at different times to access cheaper, greener power. The analysis looks at how those usage patterns change in response to price signals from Octopus Energy's smart tariffs. The findings are expected to will show how changes in energy price and demand affect consumers and what impact that has on a flexible smart grid powered increasingly by renewables.'The findings will also be shared collaboratively across industry, academia and with policy makers and regulators, with SSEN helping inform and influence the energy system of the future across GB.

6.3.3. TRANSITION

The ENA Open Networks Project (Open Networks) is focussed on defining the DNO transition to a DSO model and has been endorsed by the UK Government's Smart Systems and Flexibility Plan. Open Networks is a key platform for Whole System collaboration and communication across DNOs to enable the DSO transition.

Based on the intermediate outputs of Open Networks, TRANSITION will design, develop, demonstrate, and assess the common tools, data and system architecture required to implement the proposed models produced by the Workstream 3 project. This will include:

- Developing roles and responsibilities for market participants, and market rules to allow market participants to transact services.
- Clarifying the requirements and implement a Neutral Market Facilitator (NMF) platform for trials; and
- Engaging and consult with stakeholders.

Oxfordshire has been selected for the trials due to its replicability and high customer appetite for a smart grid architecture. Project LEO (see Section 6.3.4) is building on the outcomes and deliverables from the TRANSITION project to trial DSO models and the flexibility service marketplace and Whole Systems working.

6.3.4. LEO

Project LEO is an industry-first and has set out to explore how the growth in local renewables, electric vehicles (EVs), battery storage, vehicle-to-grid (V2G) technology and demand side response can be supported by a local, flexible, and responsive electricity grid. Thus, ensuring value for consumers and opportunities for communities and market providers.

Project Leo will be one of the most wide-ranging and holistic smart grid trials ever conducted in the UK.

The project aims to replicate, and trial aspects of the Distribution System Operator (DSO) models being explored by industry, government, and the energy regulator via the Energy Networks Associations Open Networks Project. It will balance local demand with local supply in a real-world environment, helping to test markets, inform investment models and, ultimately, assess the benefits of flexibility to the energy system.

Project LEO is already delivering useful insights on DSO and Whole System working that have directly informed our ED2 plans and strategies in these areas.

6.3.5. ENABLING DSO FUNCTIONALITY

The transition to DSO is ongoing, and the requirements will evolve as SSEN and wider industry learns more from innovation projects such as those described above. We believe that the following key enabling actions should be undertaken to facilitate the transition:

- Create digital twin of LV network to use in LV control room/control system. **This will provide real-time visibility of the network and facilitate network-wide system operation activity.**
- Capitalise on the roll out of monitoring and communications infrastructure to collect real-time data and enable DSO functions. LV monitors and other OT is being rolled out to address issues in other business areas, but the data can support wider business interests such as DSO, where data and visibility is critical. These devices can be configured to collect different datasets depending on requirements. **This will maximise the value of OT by using it to support the DSO transition as well as other business functions.**
- Develop tools to process data that is collected such that it can be used for DSO functionality
- and in the DSO services marketplace. **This will ensure flexibility and other services are procured in an efficient manner, by using accurate network data and processing it appropriately.**
- Use learnings from other DSOs on how LV DSO services can be procured and offered. **This will accelerate progress and enable us to offer a wider variety of options to our customers.**

6.3.6. DIGITAL INFRASTRUCTURE

In our Digital Strategy we have a clear vision of the digital world and what it will mean for SSEN. This vision includes access to open data, a flexible and intelligent network, a thriving DSO marketplace and an energy ecosystem with our customers and other industry participants.

The LV network must embrace this vision and take guidance from the Digital Strategy when considering the roll out of IT, OT, and communications infrastructure. Our digital infrastructure will require investment much like our electrical infrastructure and will align with LCT uptake and other decarbonisation actions.

The key actions in the Digital Strategy are:

- Continue to build the digital foundations – building critical capabilities to meet basic needs and exceed expectations. **Roll out of more extensive monitoring on the LV network will play a key role in supporting delivery of this action.**
- Building an Open Data future in the wider digital ecosystem – work with customers and industry to trial data sharing to enable Whole System collaboration. **Customer engagement will be undertaken to better understanding customer behaviour and how it may evolve**.
- Enable the future whole energy system and competition – enable a competitive marketplace underpinned by Open Data. **This will be critical to enabling flexibility at LV.**
- Continued use of the Common Network Model (CNM) as this allows the various data sets to be linked up in an interoperable way.

6.4. WHOLE SYSTEM AND STAKEHOLDER ENGAGEMENT

As a customer focused DNO, we already actively undertake stakeholder engagement. As we undertake to improve our LV network, our customers will become a key feature of our LV network operation in future. They will be empowered to interact with the network and have a real impact on how it operates as they evolve into active participants rather than passive consumers. We must enable our customers to interact with our network.

In addition, as the UK transitions to net zero, boundaries are being blurred and interdependencies created between different sectors such as electricity, gas and transport. This transition is necessitating a coordinated, Whole Systems approach to manage the energy system effectively at an efficient cost for consumers.

Working in a Whole Systems way requires local communities and authorities to collaborate with organisations in the energy, transport, telecoms, water and other sectors. For example, the decarbonisation of heat, with a range of alternative solutions (hydrogen, electric heat pumps and district heating) requires cross sector collaboration and Whole Systems thinking to optimise costs and investment while meeting environmental commitments. Similarly, the uptake of EVs requires electricity companies to collaborate with local authorities, original equipment manufacturers (OEMs) and transportation agencies (including Highways England and Transport Scotland) to ensure sufficient charging infrastructure is available across the country.

Our Whole Systems strategy provides the framework and approach for SSEN to work with our stakeholders to deliver Net Zero ambitions. This includes engaging with stakeholders such as local authorities, the

transport sector and other DNOs to share information and better understand our customers' needs to deliver our LV strategy[49].

6.4.1. CUSTOMER BEHAVIOUR

There are different parameters that we can use to measure how we think customers might behave in future, such as where they live and their socio-economic status, and these parameters play a role in how the DFES are developed.

Much like we are doing to build up our knowledge and understanding of the network and our assets, we will build our understanding of customer behaviour. This will be done in several ways, including:

- Build up picture of customer activity through collaboration with EV retailers, EV charge point installers, heat pump installers, flexibility aggregators etc. **This will provide visibility of where new technology is being connected and can feed into network analysis on asset health and demand profiles.**

- In line with our Whole Systems strategy, actively engage with local authorities and work together to develop and implement strategic plans. **This will provide wider visibility and foresight of local/regional plans that could require investment from SSEN.**

- Leverage smart meter data. **This will, over time, allow us to spot changes in behaviour patterns through changes in demand profile.**

Further to understanding the behaviour of our customers in relation to what technologies they might connect and when, will be an appreciation of how they will use these technologies. There will likely be a sliding scale of participation, from entirely passive to optimally active i.e., some customers will not change their behaviour just because they have an electric car, while others will seek to ensure they are on a tariff to reduce costs and they will modify their behaviour to suit this, they may also participate in flexibility services. The way we roll-out flexibility at LV, and how successful it will be as a network operation and management tool, will depend largely on how our customers intend to (or are incentivised to) behave and participate. It will also depend on how "ready" the local LV networks are to support flexibility services. This will require pilots and trials adopting Whole System working in close cooperation with suppliers, customers, and other third-party participants, such as aggregators.

6.5. INNOVATION AND DATA ANALYTICS

We are actively engaged in innovation and we continue to deliver projects (such as those described in section 6.3) which have data analytics aspects. Data analytics has been widely recognised, not just by SSEN but by wider industry, as having a key role in our ability to reach Net Zero. With the strategic importance of the LV network becoming more apparent, and the overall lack of visibility and understanding of the network we have now, using data and developing analytics will be paramount.

There will always be a degree of uncertainty with the LV network. Even if we have access to a large volume of data, there will always be missing information or knowledge that we don't have. We therefore need a change of mindset and philosophy – one which embraces the lack of knowledge, and makes decisions which more actively manage risks e.g. the risk of coincident EV charging etc. These risks exist on our current LV network,

[49] More detail on our Whole Systems strategy can be found in our ED2 Business Plan, Ch.12, Annex 15.

but the way that these networks have been designed (conservatively) has meant we haven't needed to consider this way of working before. Exchanging asset risk for commercial risk will become a key aspect of the LV network in future.

To support this change in philosophy, we need data and the ability to use it to quantify risks. Just having data is not enough to remove risk, we must also be able to use it to inform our decision making. The analysis used to inform the ED2 business plan (see ED2 load-related investment business plan annex for more details) is a good example of how we are using data analytics to inform our decision making on a large scale. More data will give us more information to work with (LV monitoring and smart meters) and this refines and improves the information we get out of the analysis.

6.6. DELIVERY

Taking into consideration the challenges, risks and actions required by SSEN outlined in the previous sections, we must seek to optimise these to enable us to deliver on the LV Strategic Outcomes in the most efficient way. Two key considerations we will address when approaching the development and progress of the LV network are the skills base and the supply chain.

6.6.1. SKILLS AND TRAINING

We must consider our workforce and whether we have the appropriate skills to support the actions set out in this strategy. Specifically.

- A need to **upskill our operational teams such that they can be more flexibly deployed and bring overall efficiencies to the business** and our customers.
- Recognition of the potential emergence of skills gap, specifically at LV, where **we will need power systems expertise as well as data analytics knowledge**.

The two skillsets will complement one another, and teams will need to communicate more effectively to ensure we are able to translate data into information and ultimately decisions.

6.6.2. SUPPLY CHAIN

We must work with our supply chain to ensure we are able to deliver what we set out to deliver as per this strategy. The energy transition is not unique to SSEN and similar activities are likely going on within the other UK DNOs. There are potentially huge volumes of monitoring equipment, circuits, transformers and other equipment going to be needed in the coming years and so **we must look to mitigate potential bottlenecks in the supply chain as much as possible by developing a robust procurement strategy.**

Appendix E KEY TRENDS IN DFES SCENARIOS

Here we summarize some of the most important trends central to our analysis for the ED2 period. The full DFES documents for 2020 in the North and South should be consulted for a detailed analysis of technology evolution across our licence areas.

Key 'North' trends

- **Onshore wind:**
  - The area has a strong presence of large-scale and small-scale onshore wind deployed over the last 20 years;
  - A large pipeline of viable projects, many with planning permission, drives strong capacity growth in the near term as new routes to market for onshore wind appear and new projects become increasingly commercially viable and deployment certainty increases;
  - The area has an excellent amount of developable wind resource, resulting in increased connected capacity out to 2050 in all scenarios;
  - A significant amount of new capacity is also driven by repowering of existing sites with more efficient and higher capacity turbines
- **Hydropower:**
  - The area represents a large proportion of the UK's current and potential future distributed hydropower capacity;
  - The majority of the 807 MW currently connected consists of large-scale projects, built up to 70 years ago, with no further development of this equivalent scale seen in almost 20 years;
  - The future potential for additional capacity is likely to be single-MW or smaller scale projects, as most opportunities for large-scale hydro generation have largely been exploited. The level any additional capacity is uncertain and dependent on whether small-scale renewable generation is supported. The recent Feed-in Tariff has given a good indication of how subsidy has allowed some new hydropower generation to be commissioned, despite being a mature technology;
  - Therefore, scenario projections for distribution network hydropower capacity in the area are highest in Consumer Transformation and Leading the Way, where small-scale renewables play a vital role in achieving net zero. Under System Transformation and Steady Progression, hydropower development in limited in the area
- **Electricity storage:**
  - A significant amount of distribution network connected battery storage capacity (MW) is seen in all scenarios by 2050, compared to the very small 1.2 MW today;
  - This reflects a significant near-term pipeline of 668 MW, including several projects that are in the c.20-50 MW range;

- The highest connected is in the Leading the Way scenario, with c.1.2 GW modelled to connect to the distribution network by 2050. This is ~6% of the FES 2020 total GB projected capacity on the distribution network in this scenario by 2050. This reflects a moderate proportion of the pipeline going through to connection, additional standalone, generation co-location and high energy user projects connecting in the medium term and a notable overall uptake of domestic batteries by 2050 in this scenario
- The lowest connected capacity is seen in the System Transformation scenario, with 290 MW connected by 2050. This reflects a more general scenario assumption of a lesser need for distribution network connected flexibility, overall lower levels of electrification and renewable electricity generation deployment and a significantly lower uptake of domestic batteries. Also with the transmission network in Scotland being a voltage tier lower than the rest of the UK, some additional battery storage projects that may be connecting at 132kV between 2019 and 2050 are not within the scope of the DFES analysis for the North of Scotland licence area;
- Whilst a significant increase in connected capacity is seen in all scenarios by 2050, beyond the sizeable pipeline there is a degree of uncertainty around the development of battery storage projects under any business model. This uncertainty relates to high levels of competition in national and local flexibility markets and challenging network charging reforms that could adversely impact the commercial viability of distribution network battery storage assets in the longer term. With the strong level of distribution network connected generation seen in the North of Scotland area (especially onshore wind), the proposed introduction of higher network costs in substation areas that are 'generation dominated', could possibly affect the viability of distribution network generation in the area. With battery storage currently being classed as a subset of generation for network charging purposes, this may similarly affect the connection costs for the export capacity element of a battery storage connection offer. However, with the clear network support and flexibility role that storage could provide to the electricity network in the area, Ofgem could consider either a dispensation or adjusting regulation for electricity storage in the future

- **Electric Vehicles**:
  - At present, EVs (including plug-in hybrids) represent approximately 0.7% of all vehicles in the North of Scotland area, which is below the GB average of nearly 1%. This is, however, representative of other predominantly rural regions in GB. More urban centres in the region, such as for Dundee and Stirling city regions, have an EV uptake more typical of GB average
  - However, as a result of Scottish Government's ambition for transport decarbonisation, North of Scotland is projected to align with the GB average uptake rate for EV's by the mid-2020s;
  - Electrification is the key route to decarbonising transport in the scenarios, with hydrogen's role focussed in contributing to the decarbonisation of HGVs and buses in most scenarios. North of Scotland is projected to have a higher uptake of hydrogen vehicles compared to the national scenarios

- **Electric vehicle chargers**:
  - At present, the installation of public EV chargers is significantly above the GB average per EV vehicle in the North of Scotland area. The density of chargers is less if compared to the geographical size of the region. This reflects the support received and 'Chargeplace

Scotland's' active participation in the Scottish EV charger market. This trend is expected to continue in the near-term, until demand for charging increases;

- Hot spots for public charger deployment include some of the urban areas as well as some of the islands and tourist areas.
- There is significant uncertainty regarding the shape and size of the future charger network; in particular the split between off-street home charging versus public charging, as well as the market share between ultra-fast charging hubs versus lower voltage on-street, neighbourhood and municipal charging. The DFES projections therefore aim to represent the envelope of the possible spread and rate of deployment of EV chargers. In many modelling areas there is a lack of behavioural evidence and so interim assumptions have been made;

- **Heat pumps and direct electric heating**:
  - In line with decarbonisation strategies across the country, the North of Scotland area sees a dramatic shift to low carbon heating in all three of the scenarios that meet net zero targets;
  - Engagement with Scottish Government around heat decarbonisation ambition (including some of measures and targets highlighted in the recently published Climate Change Plan) has been reflected in all scenarios, particularly under Consumer Transformation and Leading the Way. This results in the North of Scotland area seeing rapid heat pump roll-out in the near and medium term, reflecting high levels of ambition to decarbonise off-gas and on-gas homes in Scotland. This has a correlative effect of limiting the uptake of hybrid heat pumps, which are not a focus of Scottish Government's heat decarbonisation strategy;
  - In the more electrified Consumer Transformation and Leading the Way scenarios, ~77% of homes are heated by a non-hybrid or hybrid heat pump by 2045, as Scotland's net zero target year. Whilst not directly connecting or impacting the electricity distribution network, it should be noted that the remaining 23% of homes in the area will also be heated by alternative low carbon heating technologies, such as hydrogen boilers or district heat networks;
  - The North of Scotland is a unique area, with many factors directly impacting low carbon heating options. 44% of homes in the area are not connected to the mains gas network, three times the GB proportion of 15%. This results in heat pumps playing a strong role in heat decarbonisation across the licence area, even in scenarios where hydrogen is available for heating on-gas homes;
  - Furthermore, the particularly rural and remote areas of the Highlands and Islands in the north and west of the area experience high prices for oil, LPG and solid heating fuels. This has already resulted in high levels of electrified heat in these areas;
  - Uptake of commercial heat pumps see a similar trajectory to domestic heat pumps. However, the penetration of heat pumps is lower than in domestic homes, due to the higher proportion of commercial units expected to use direct electric heating throughout the scenario timeframe. Currently, according to non-domestic EPC records, almost 50% of GB commercial properties are heated by electric heating, compared to 8% of domestic households;

- Under the Consumer Transformation and Leading the Way scenarios, just over 60% of commercial properties are heated by a form of heat pump in 2050. Leading the Way has a significantly higher number of hybrid heat pumps;
- Direct electric heating is compliant with net zero emissions targets and is therefore not explicitly targeted for heat decarbonisation measures. However, as one of the most expensive heating methods and being less fuel-conversion efficient than heat pumps, scenarios with high levels of support for low carbon heating solutions will see a reduction in existing homes with direct electric heating over time. Scottish Government, through the Scottish Fuel Poverty Act (2019) seeks to eradicate fuel poverty as far as is reasonably possible by 2040, therefore solutions such as direct electric heating is one of the solutions considered when aiming to tackle carbon emissions and fuel poverty;
- Conversely, direct electric heating is currently installed in some new build homes, and this will elicit an increase in direct electric heating deployment in homes in some scenarios, particularly in the near-term. • In the long-term, all three net zero scenarios see a reduction in direct electric heated homes from today's levels, due to the prevalence of affordable electric heat pumps, hydrogen heating or low carbon district heat networks for the majority of homes in these scenarios. District heat networks, whilst not likely to be primarily fuelled by electricity, is a low carbon heating solution that is another key feature of Scottish Government's heat decarbonisation strategy. Therefore, whilst not a specific output or projection under the DFES 2020 scenarios, there could be a notable role for low carbon district heat networks supplying some clusters of homes in more urbanised areas of North Scotland in the longer term, especially under the System Transformation scenario

- **Small scale solar PV:**
  - Domestic-scale solar PV has historically seen high levels of uptake in the North of Scotland licence area, despite the lower levels of irradiance compared to the rest of the country. This deployment was driven by particularly high rates in the early years of the Feed-in Tariff;
  - While domestic-scale solar PV is a more attractive investment in sunnier regions, levels of irradiance are less influential on uptake compared to utility-scale ground-mounted solar PV. As a result, the capacity of domestic-scale solar PV in the licence area is expected to broadly align with national trends in each of the four scenarios, driven largely by consumer engagement, uptake of other domestic technologies (such as electric vehicles and domestic batteries), and a future reduction in the costs of domestic solar array installations. In the highly ambitious Consumer Transformation scenario, around one in six domestic properties host rooftop PV by 2050;
  - Small-scale commercial-scale solar PV is typically impacted by a blend of the drivers of domestic-scale and utility-scale solar PV. Consequently, commercial-scale solar PV deployment has a similar trajectory to these technologies, with strong capacity growth under the Consumer Transformation scenario in particular

Key 'South' trends

- **Large scale solar PV**:
  - Due to the high levels of irradiance relative to the rest of the UK, the Southern England area has some of the highest levels of largescale solar PV deployment in the country;

- This level of development interest is expected to continue throughout the timeframe of the scenarios out to 2050, due to the attractive levels of solar irradiance, though not to the same extent as in the baseline years. This is due to solar PV costs continuing to fall, resulting in ground mounted solar PV projects being built out across all of GB rather than only in the south of the country;
- With solar PV panel efficiencies also increasing continuously, there is the potential for the repowering of baseline sites to drive a large increase in overall solar PV capacity as projects reach the end of their operational life

- **Gas fired generation**:
  - The connected capacity of decentralised natural gas fired generation in the Southern England area is above average when compared to some other parts of the UK
  - Currently connected is ~550 MW reflective of a strong gas network coverage in the area, as well as notable industrial regions such as Swindon, Portsmouth, and West London;
  - As well as three sizeable OCGT sites, there are several gas CHPs and reciprocating engine projects of varying capacities connected across the area. There is also a significant pipeline of ~419 MW of potential new natural gas generation sites in the area, which is a mixture of all three natural gas sub-technologies;
  - The DFES analysis for gas generation in the Southern area has therefore focused on three distinct areas:
    1. Modelling the potential future pathways for each of the natural gas sub-technology sites in the baseline. This modelling specifically looks at the potential for many of these baseline sites to decommission across the 2030s and 2040s, in line with the Leading the Way, Consumer Transformation and System Transformation scenarios meeting net zero emissions by 2050;
    2. Assessing the development potential for the significant pipeline, as new/additional fossil fuel generators, within the scenarios and the equivalent future decommissioning of these sites, likely to mostly be within the 2040s;
    3. The longer term DFES analysis also considers the potential for some of the known baseline/pipeline projects that may operate more commercially, to convert their generator assets to be able to run on hydrogen instead of natural gas. This has been determined to mostly likely be in city or local authority regions within the area that have been identified as hydrogen supply zones
  - For the three scenarios that are compliant with the target to achieve net zero emissions by 2050 in England, all-natural gas generation is decommissioned before 2045 and a small amount of hydrogen fuelled generation capacity is modelled to come online between 2035 and 2050. In the Steady Progression scenario, the total connected capacity of natural gas generation is higher in the area in 2050 than in 2019, though this connected capacity peaks across the 2030s and sees a small decline across the 2040s. At a high level, the long-term role of natural gas and hydrogen fuelled generation is uncertain. Gas generation is an inherently flexible and responsive technology, that can potentially support the operability of the electricity system in the near-term. However, with natural gas being a carbon intensive fuel and with exhaust emission abatement technologies potentially being prohibitively costly to fit to smaller scale generators, the running of unabated natural gas generation in the long-term is at odds with net zero emission targets. Add to this the significant level of uncertainty around the likely strategy for

hydrogen production, hydrogen supply infrastructure and the locational or national scale of hydrogen demand, the potential scale of hydrogen fuelled generation is equally uncertain. This uncertainty is reflected through a notable spread of capacity trajectories across the scenarios

- **Electricity storage**:
  - In the Southern area, a significant amount of distribution network connected battery storage capacity (MW) is seen in all scenarios by 2050, compared to a relatively small 3.2 MW today;
  - This reflects a significant near-term known pipeline of 736 MW, including two projects that are greater than 100 MW and several others that are in the c.30-50 MW range;
  - The highest connected capacity is in the Leading the Way scenario, with ~2 GW modelled to connect to the distribution network by 2050. This is ~12% of the FES 2020 total GB projected capacity on the distribution network in this scenario by 2050. This reflects a significant proportion of the pipeline going through to connection, as well as additional standalone, co-location and high energy user projects connecting in the medium term and a notable uptake of domestic batteries by 2050 in this scenario;
  - The lowest connected capacity is seen in the System Transformation scenario, with ~0.4 GW connected by 2050. This reflects a more general scenario assumption of a lesser need for distribution network connected flexibility and overall lower levels of electrification and renewable electricity generation deployment. It also reflects a significantly lower uptake of domestic batteries;
  - Whilst a notable increase in connected capacity is seen in all scenarios by 2050, beyond the sizeable pipeline there is a degree of uncertainty around the development of battery storage projects under any business model. This uncertainty relates to high levels of competition in national and local flexibility markets and network charging reforms that could impact the long-term business case of distribution network storage assets. The degree of uncertainty impacting deployment under each storage business model has been reflected through the four scenarios
- **Electric vehicles**:
  - At present, EVs represent approximately 1.1% of all vehicles in the Southern area, which is above the GB average of nearly 1%. The EV uptake rate in the Southern area is expected to remain ahead of the GB average until the late 2020s in most scenarios, when EV uptake becomes increasingly ubiquitous;
  - Electrification is the key route to decarbonising transport in the scenarios, with hydrogen contributing to the decarbonisation of HGVs and buses
- **Electric vehicle chargers**:
  - At present, the installation of public EV chargers in the Southern area is approximately the same as the GB average. This trend is expected to continue as EVs become increasingly ubiquitous in the medium term;
  - Compared to the previous 'SSEN High granularity projections for low carbon technology[50]' report, the uptake rate of EV chargers is higher and the envelope of charger capacity in 2050 has narrowed. This is predominantly due to an increased uptake of EVs in the less

[50] High granularity projections for low carbon technology uptake, June 2020: **https://www.regen.co.uk/wp-content/uploads/Regen-SSEN-High-granularityLCT-projections-Final.pdf**

ambitious scenarios in the scenario compared to the 2019 report, thus narrowing the EV uptake projections;

- **Heat pumps and direct electric heating**:
  - In line with decarbonisation strategies across the country, the Southern area sees a dramatic shift to low carbon heating in all three of the net zero compliant scenarios;
  - In the more electrified Consumer Transformation and Leading the Way scenarios, there is a significant increase in heat pump deployment during the next decade. This is consistent with the UK government's target to deploy 600,000 heat pumps per year by 2028 as well as the legal commitment to meet the 4th and 5th carbon budgets. By 2050 ~70% of homes are heated by a non-hybrid or hybrid heat pump;
  - The housing stock in the area is broadly like the average GB home when considering energy efficiency, size, building form and tenure. However, 23% of houses in the area are not connected to the gas network, significantly above the national average of 15%. This results in heat pump uptake exceeding the national trajectory, particularly in the near and medium term where off-gas homes are more likely to convert to a heat pump. The lower number of on-gas homes also reduces the uptake of hybrid heat pumps;
  - Uptake of commercial heat pumps experiences a similar trajectory to domestic heat pumps. However, the penetration of heat pumps is lower than in domestic homes, due to the higher proportion of commercial units expected to use direct electric heating throughout the scenario timeframe. Currently, according to non-domestic EPC records, almost 50% of GB commercial properties are heated by electric heating, compared to 8% of domestic households;
  - Under the Consumer Transformation and Leading the Way scenarios, just over 60% of commercial properties are heated by a form of heat pump in 2050. Leading the Way has a significantly higher proportion of hybrid heat pumps. • Direct electric heating is compliant with net zero emissions targets and is therefore not explicitly targeted for heat decarbonisation measures. However, as one of the most expensive heating methods, scenarios with high levels of support for low carbon heating solutions such as heat pumps will see a reduction in existing homes with direct electric heating over time;
  - Conversely, direct electric heating is currently installed in some new build homes, and this will elicit an increase in directly heating homes in some scenarios, particularly in the near-term
  - In the long-term, all three net zero scenarios see a reduction in direct electric heated homes from today's levels, due to the prevalence of affordable electric heat pumps, hydrogen heating or low carbon district heat networks for the majority of homes in these scenarios
- **Small scale solar**:
  - Domestic-scale solar PV in the Southern England licence area has historically seen levels of uptake area in line with the national average, despite having higher levels of irradiance compared to the rest of the country. This deployment was driven by Feed-in Tariff support in the 2010s
  - While domestic-scale solar PV is a more attractive investment in sunnier regions, levels of irradiance are less influential on uptake compared to utility-scale ground-mounted solar PV. As a result, capacity of domestic-scale solar PV in the licence area is expected to broadly align with national trends in each of the four scenarios. This is driven largely by

consumer engagement, uptake of other domestic technologies (such as electric vehicles and domestic batteries), and reduction in the costs of domestic solar array installations;

- In the highly ambitious Consumer Transformation scenario, around one in six domestic properties hosts rooftop solar PV by 2050;
- Commercial-scale solar PV is typically impacted by a blend of the drivers of domestic-scale and utility-scale solar PV. Consequently, commercial-scale solar PV deployment sees a similar trajectory to these technologies, with a strong increase in connected capacity under the Consumer Transformation scenario in particular

- **Data centres**:
  - New data centres have the potential to significantly increase electricity demand on the distribution network. They could also potentially become enablers for battery storage, DSR flexibility and sources of heat for heat networks;
  - There are 13 proposed data centre developments with accepted connection offers in the Southern area, totalling 665 MW;
  - Four of these data centres have an accepted import capacity of more than 100 MW;
  - Through discussions with SSEN network planners, many of these sites have proposed staged development, where a proportion of the full accepted import connection is modelled to come online over 3-5 years;
  - This represents a significant amount of new electricity demand on the distribution network in the Southern England licence in the 2020s;
  - Once committed, Data Centre projects tend to have a high acceptance rate and likelihood of being commissioned. The projections have therefore been applied across all four scenarios;
  - Beyond these known projects, no additional capacity has been projected, due to the lack of future development data, FES 2020 scenario projections and publicly available information

- **Domestic air conditioning**:
  - Our estimates of existing domestic AC units has been based on an assumption that nationally, ~1% of homes on average across GB currently have AC units
  - These AC units are likely to mostly be in flats and apartment buildings. With some areas of the Southern England area having notable population density (including more multi-occupancy buildings) and a hotter climate in Southern England, the national figure of 1% has been applied to the area to determine the baseline. This equates to a little over 25,000 AC units in 2019;
  - Based on the National Grid FES 2020 residential energy consumption datasets, domestic AC unit capacity (kW) and assumptions around operating hours, the DFES analysis has projected a significant range of results for AC deployment across the scenarios by 2050:
    - The highest number is seen in Steady Progression, with just under 1.5 million units (~44% of all homes in the area);
    - The lowest number is seen in Leading the Way, with just under 30,000 units (~1% of all homes in the area)

Appendix F SUMMARY OF LOAD-RELATED EXPENDITURE PROJECTS

Licence area	IDP submitted	Reference no.	LRE Bucket	Scheme name	CAPEX (£m)	Delivery year	SP	ST	CT	LW	Reporting table
SEPD	Yes	44/SEPD/LRE/SCO	Baseline	Fleet and Bramley 400/132kV Substation Group	43.7	2027/28		x	x	x	CV1
SEPD	No	45/SEPD/LRE/YEOVIL	Baseline	Yeovil 132/33 kV Bulk Supply Point Substation	1.7	2024/25		x	x	x	CV1
SEPD	Yes	47/SEPD/LRE/BEAC	Baseline	Beaconsfield 22/6.6 kV Primary Substation	4.2	2025/26		x	x	x	CV1
SEPD	Yes	48/SEPD/LRE/ASHR	Baseline	Ashling Road 33/11 kV Primary Substation	4.4	2026/27		x	x	x	CV1
SEPD	Yes	50/SEPD/LRE/HARL	Baseline	Harvard Lane 22/11 kV Primary Substation	5.2	2026/27	x	x	x	x	CV1
SEPD	Yes	51/SEPD/LRE/STOK	Baseline	Stokenchurch 33/11 kV Primary Substation	3.5	2024/25	x	x	x	x	CV1
SEPD	Yes	53/SEPD/LRE/EGHA	Baseline	Egham 33/11 kV Primary Transformers and 33 kV Circuit Reinforcements	3.6	2026/27	x	x	x	x	CV1
SEPD	Yes	54/SEPD/LRE/ASHP	Baseline	Ashton Park 33 kV Circuits	3.0	2025/26	x	x	x	x	CV1
SEPD	Yes	55/SEPD/LRE/MILT	Baseline	33 kV Circuits of Fulscot 33/11 kV Primary Substations	2.0	2025/26	x	x	x	x	CV1
SEPD	Yes	56/SEPD/LRE/NETLEY	Baseline	Netley Common BSP 132/33 kV Substation	3.2	2025/26		x	x	x	CV1
SEPD	Yes	57/SEPD/LRE/AMESBURY	Baseline	Amesbury 132 kV isolator (S) / Salisbury 132 kV circuit breaker bay (P) / 132kV	1.6	2024/25	x	x	x	x	CV1
SEPD	Yes	58/SEPD/LRE/ALTON	Baseline	Alton - Fernhurst 132 kV Network Reinforcement	7.3	2023/24	x	x	x	x	CV1
SEPD	Yes	59/SEPD/LRE/BRAMLEY_THATCHAM	Baseline	Bramley - Thatcham - Andover 132 kV Reinforcement	4.7	2023/24	x	x	x	x	CV1
SEPD	Yes	60/SEPD/LRE/IVER	Baseline	Iver 132 kV Fault Level Reinforcement	22.8	2025/26	x	x	x	x	CV3
SEPD	Yes	61/SEPD/LRE/FAWLEY	Baseline	132 kV Fawley (P) / SCO Reinforcement Fawley North (S) / 132kV	0.7	2023/24	x	x	x	x	CV1
SEPD	Yes	62/SEPD/LRE/MANNINGTON	Baseline	Mannington 132/33 kV substation (P) / Mill Lane 33/11 kV substation (S) / CB Replacement	0.3	2023/24	x	x	x	x	CV1
SEPD	Yes	64/SEPD/LRE/FROME	Baseline	Frome BSP 132 kV Circuit and 132/33 kV Transformer	2.4	2024/25	x	x	x	x	CV1
SEPD	Yes	65/SEPD/LRE/EBED	Baseline	East Bedford A 132/22 kV Substation Reinforcement	6.0	2026/27	x	x	x	x	CV1

Licence area	IDP submitted	Reference no.	LRE Bucket	Scheme name	CAPEX (£m)	Delivery year	SP	ST	CT	LW	Reporting table
SEPD	Yes	66/SEPD/LRE/Upton	Baseline	Upton EHV System Reinforcement	10.3	2024/25	x	x	x	x	CV1
SEPD/ SHEPD	Yes	423/SSEPD/LRE/TRANSMISSION_CHARGES	Baseline	New Transmission Capacity Charges	19.4	2023/24-2027/28	N/A due to programme of works				CV4
SEPD	Yes	365/SEPD/LRE/POLE	Baseline	Rutter Pole Replacement Scheme	17.3	2023/24-2027/28	N/A due to programme of works				CV1
SEPD	No	63/SEPD/LRE/DENHAM	Baseline	Denham 132kV circuits	0.3	2024/25	x	x	x	x	CV1
SEPD	Yes	107/SEPD/LRE/LOUDWATER	Baseline	Loudwater BSP 132/33kV Transformer and 132kV circuits	9.6	2025/26	x	x	x	x	CV1
SEPD	No	110/SEPD/LRE/YETM	Baseline	Yetminster Primary 33 kV circuits	0.5	2024/25	x	x	x	x	CV1
SEPD	No	119/SEPD/LRE/OXFORD	Strategic Investment	Oxford (Osney) GSP 132 kV Circuits	0.1	2024/25			x	x	CV1
SEPD	No	121/SEPD/LRE/BERI	Baseline	Berinsfield Primary 33kV circuits	1.0	2025/26	x	x	x	x	CV1
SEPD	No	125/SEPD/LRE/STLA	Baseline	Standlake Primary 33/11kV transformers	1.1	2024/25	x	x	x	x	CV1
SEPD	Yes	127/SEPD/LRE/CHAR-WOOD	Baseline	Charlbury-Woodstock 33 kV Ring Network Reinforcement	4.7	2023/24		x	x	x	CV1
SEPD	No	130/SEPD/LRE/ALRE	Baseline	Alresford Primary 33kV circuits ,33/11kV transformers	1.7	2025/26, 2027/28	x	x	x	x	CV1
SEPD	No	132/SEPD/LRE/WARF	Baseline	Warfield Primary 33kV circuits	1.3	2025/26	x	x	x	x	CV1
SEPD	No	133/SEPD/LRE/GORI-CHOL	Baseline	Goring & Cholsey Primary 33kV circuits	0.5	2024/25	x	x	x	x	CV1
SEPD	Yes	142/SEPD/LRE/WYMERING_PORTSMOUTH	Strategic Investment	Wymering and Portsmouth BSP 132/33KV transformers and 132kV circuits	13.5	2026/27			x	x	CV1
SEPD	No	150/SEPD/LRE/BIRD	Baseline	Birdham Primary 33/11kV Transformers	1.1	2024/25		x	x	x	CV1
SEPD	No	156/SEPD/LRE/BEME	Baseline	Bemerton Ring 33kV circuits	0.5	2023/24, 2025/26	x	x	x	x	CV1
SEPD	No	159/SEPD/LRE/FEDO_WIMB	Baseline	Wimborne Primary 33/11 kV Transformers and 33kV supply circuits	1.8	2025/26, 2027/28	x	x	x	x	CV1
SEPD	No	162/SEPD/LRE/BOUR	Baseline	Bourton Primary 33 kV supply circuits	0.4	2024/25	x	x	x	x	CV1
SEPD	No	164/SEPD/LRE/WART	Baseline	Wareham Town Primary 33kV circuits	0.4	2026/27	x	x	x	x	CV1
SEPD	No	165/SEPD/LRE/CALN	Baseline	Calne Primary 33KV circuits	1.4	2024/25	x	x	x	x	CV1
SEPD	No	167/SEPD/LRE/ALDE	Baseline	Alderton Primary 33/11kV transformers	1.1	2025/26		x	x	x	CV1
SEPD	No	169/SEPD/LRE/BRUT	Baseline	Bruton Primary 33kV Supply Circuits	0.7	2024/25, 2027/28		x	x	x	CV1
SEPD	Yes	170/SEPD/LRE/FROM_WBUR	Baseline	Frome-Westbury 33 kV Ring Network Reinforcement	1.7	2025/06	x	x	x	x	CV1

Licence area	IDP submitted	Reference no.	LRE Bucket	Scheme name	CAPEX (£m)	Delivery year	SP	ST	CT	LW	Reporting table
SEPD	No	176/SEPD/LRE/FARI	Baseline	Faringdon Primary 33/11kV transformers	1.1	2024/25	x	x	x	x	CV1
SEPD	No	182/SEPD/LRE/BISH	Baseline	Bishopstoke Primary 33kV circuits	1.8	2026/27	x	x	x	x	CV1
SEPD	No	183/SEPD/LRE/YATT	Baseline	Yattendon Ring 33kV circuit	0.5	2024/25		x	x	x	CV1
SEPD	No	188/SEPD/LRE/SHIO	Strategic Investment	Shipton Oliffe Primary 33/11 kV transformer	1.1	2027/28			x	x	CV1
SEPD	No	190/SEPD/LRE/CHIPPENHAM	Baseline	CHIPPENHAM 33kV circuit breaker reinforcement	0.1	2025/26		x	x	x	CV3
SEPD	No	192/SEPD/LRE/LYTCHETT	Baseline	LYTCHETT 33kV circuit breaker reinforcement	1.1	2025/26		x	x	x	CV3
SEPD	No	194/SEPD/LRE/SOUTHAMPTON	Baseline	SOUTHAMPTON 33kV circuit breaker reinforcement	0.9	2025/26		x	x	x	CV3
SEPD	No	195/SEPD/LRE/STRATTON	Baseline	STRATTON 33kV circuit breaker reinforcement	0.4	2023/24	x	x	x	x	CV3
SEPD	No	196/SEPD/LRE/SWINDON	Baseline	SWINDON 33kV fault level reinforcement	1.1	2023/24	x	x	x	x	CV3
SEPD	No	197/SEPD/LRE/SWINDON	Baseline	SWINDON 11kV fault level reinforcement	0.5	2023/24	x	x	x	x	CV3
SEPD	No	198/SEPD/LRE/WOOTTON	Baseline	WOOTTON COMMON 33kV circuit breaker reinforcement	0.3	2023/24	x	x	x	x	CV3
SEPD	No	199/SEPD/LRE/COCKLEBURY	Baseline	COCKLEBURY 11kV circuit breaker reinfocement	0.1	2023/24		x	x	x	CV3
SEPD	No	200/SEPD/LRE/DRAKES	Baseline	DRAKES WAY 33kV circuit breaker reinforcement	0.1	2023/24	x	x	x	x	CV3
SEPD	No	201/SEPD/LRE/SHRIVENHAM	Baseline	SHRIVENHAM 11kV circuit breaker reinforcement	0.3	2025/26	x	x	x	x	CV3
SEPD	No	202/SEPD/LRE/STEEL_SWINDON	Baseline	PRESSED STEEL SWINDON 11kV fault level reinforcement	0.3	2023/24	x	x	x	x	CV3
SEPD	No	203/SEPD/LRE/QUARRYRD	Strategic Investment	QUARRY ROAD 11kV circuit breaker reinforcement	0.1	2025/26			x	x	CV3
SEPD	No	204/SEPD/LRE/MILTON	Baseline	MILTON 11kV circuit breaker reinforcement	0.1	2023/24	x	x	x	x	CV3
SEPD	No	207/SEPD/LRE/SUNBURY	Baseline	SUNBURY CROSS 11kV fault level reinforcement	0.9	2023/24	x	x	x	x	CV3
SEPD	No	210/SEPD/LRE/HILSEA	Baseline	HILSEA 33kV circuit breaker reinforcement	0.1	2023/24	x	x	x	x	CV3
SEPD	No	211/SEPD/LRE/WESPLANADE	Baseline	WESTERN ESPLANADE 11kV circuit breaker reinforcement	0.1	2025/26		x	x	x	CV3
SEPD	No	212/SEPD/LRE/MAYBUSH	Baseline	MAYBUSH 11kV circuit breaker reinforcement	0.4	2023/24	x	x	x	x	CV3
SEPD	No	213/SEPD/LRE/NORTHOLT	Strategic Investment	NORTHOLT 11kV circuit breaker reinforcement	0.7	2023/24			x	x	CV3
SEPD	No	214/SEPD/LRE/EALING	Baseline	EALING 66kV GSP fault level reinforcement	1.8	2023/24	x	x	x	x	CV3

Licence area	IDP submitted	Reference no.	LRE Bucket	Scheme name	CAPEX (£m)	Delivery year	SP	ST	CT	LW	Reporting table
SEPD	No	215/SEPD/LRE/EALING	Baseline	EALING 22kV circuit breaker reinforcement	1.7	2023/24	x	x	x	x	CV3
SEPD/ SHEPD	Yes	70/SHEPD/LRE/LVFeeders	Baseline/Strategic Investment	LV feeders - Load related	36.0	2023/24-2027/28	N/A due to programme of works				CV2
SEPD/ SHEPD	Yes	69/SHEPD/LRE/Feeders	Baseline/Strategic Investment	HV feeders - Load related	41.5	2023/24-2027/28	N/A due to programme of works				CV2, CV3
SEPD/ SHEPD	Yes	68/SEPD/LRE/Stransformers	Baseline/Strategic Investment	Secondary distribution transformers - Load related	49.3	2023/24-2027/28	N/A due to programme of works				CV2
SHEPD	No	251/SHEPD/LRE/ELLON	Strategic Investment	ELLON 33/11kV Transformer	0.73	2026/27			x	x	CV1
SHEPD	No	71/SHEPD/LRE/SCORRDALE	Baseline	SCORRADALE 33kV Circuits	0.56	2025/26	x	x	x	x	CV1
SHEPD	Yes	72/SHEPD/LRE/KEITH	Baseline	KEITH 33kV Circuits	4.32	2023/24	x	x	x	x	CV1
SHEPD	No	73/SHEPD/LRE/INVERNESS	Baseline	INVERNESS 33kV Circuits	0.34	2023/24, 2024/25	x	x	x	x	CV1
SHEPD	No	74/SHEPD/LRE/TAYNUILT	Baseline	TAYNUILT 33kV Circuits	0.10	2023/24	x	x	x	x	CV1
SHEPD	No	75/SHEPD/LRE/ABERNETHY	Baseline	ABERNETHY 33kV Circuits	0.88	2024/25	x	x	x	x	CV1
SHEPD	Yes	77/SHEPD/LRE/STMARYS	Baseline	ST MARY Primary Substation Reinforcements	3.59	2024/25	x	x	x	x	CV1
SHEPD	Yes	78/SHEPD/LRE/KILNIVER	Baseline	KILNINVER Primary Substation Reinforcements	4.53	2025/26	x	x	x	x	CV1
SHEPD	Yes	79/SHEPD/LRE/SKULAMUS	Baseline	SKULAMUS Primary Substation Reinforcements	2.48	2024/25	x	x	x	x	CV1
SHEPD	No	80/SHEPD/LRE/DUNOON	Strategic Investment	DUNOON 33 kV Circuits	0.45	2023/24, 2024/25			x	x	CV1
SHEPD	Yes	82/SHEPD/LRE/PORTANN	Baseline	PORT ANN 33 kV Circuits	4.16	2023/24, 2025/26	x	x	x	x	CV1
SHEPD	No	83/SHEPD/LRE/THURSO	Baseline	THURSO SOUTH 33 kV Circuits	0.37	2023/24	x	x	x	x	CV1
SHEPD	No	227/SHEPD/LRE/BRIDGEDON	Baseline	BRIDGE OF DON 33/11kV Transformer	0.86	2026/27	x	x	x	x	CV1
SHEPD	No	230/SHEPD/LRE/BURGHMUIR	Baseline	BURGHMUIR 33 kV Circuits	0.01	2025/26	x	x	x	x	CV1
SHEPD	No	232/SHEPD/LRE/CASHILE	Baseline	CASHLIE 33/11kV Transformer	0.36	2023/24	x	x	x	x	CV1
SHEPD	No	244/SHEPD/LRE/CULLODEN	Baseline	CULLODEN 33/11kV Transformer	0.71	2026/27		x	x	x	CV1
SHEPD	No	247/SHEPD/LRE/DRUMRUNIE	Baseline	DRUMRUNIE 33/11kV Transformer	0.36	2023/24	x	x	x	x	CV1
SHEPD	No	249/SHEPD/LRE/DUNVEGAN	Baseline	DUNVEGAN 33 kV Circuits	0.03	2023/24	x	x	x	x	CV1
SHEPD	No	250/SHEPD/LRE/ELGIN	Baseline	ELGIN 33 kV Circuits	0.45	2023/24, 2027/28	x	x	x	x	CV1

Licence area	IDP submitted	Reference no.	LRE Bucket	Scheme name	CAPEX (£m)	Delivery year	SP	ST	CT	LW	Reporting table
SHEPD	No	256/SHEPD/LRE/GISLA	Baseline	GISLA 33/11kV Transformer	0.36	2023/24	x	x	x	x	CV1
SHEPD	No	259/SHEPD/LRE/HALKIRK	Baseline	HALKIRK 33/11kV Transformer	0.37	2026/27	x	x	x	x	CV1
SHEPD	No	260/SHEPD/LRE/INSCH	Strategic Investment	INSCH 33/11kV Transformer	0.71	2023/24			x	x	CV1
SHEPD	No	261/SHEPD/LRE/INVERBROOM	Baseline	INVERBROOM 33/11kV Transformer	0.02	2026/27	x	x	x	x	CV1
SHEPD	No	269/SHEPD/LRE/LOCHCARNAN	Baseline	LOCH CARNAN 33 kV Circuits	1.03	2023/24, 2027/28	x	x	x	x	CV1
SHEPD	No	276/SHEPD/LRE/MINORGRUDIE	Baseline	MINOR GRUDIE 33/11kV Transformer	0.02	2023/24	x	x	x	x	CV1
SHEPD	No	281/SHEPD/LRE/NEWPITSLIGO	Baseline	NEW PITSLIGO 33/11kV Transformer	0.71	2023/24	x	x	x	x	CV1
SHEPD	No	286/SHEPD/LRE/QUOICH	Baseline	QUOICH 33/11kV Transformer	0.36	2023/24	x	x	x	x	CV1
SHEPD	No	287/SHEPD/LRE/RANNOCH	Baseline	RANNOCH 33 kV Circuits	0.67	2023/24	x	x	x	x	CV1
SHEPD	No	289/SHEPD/LRE/GRUDIEBRIDGE	Baseline	Regulator at Grudie Bridge Regulator	0.36	2023/24	x	x	x	x	CV1
SHEPD	No	294/SHEPD/LRE/SHIELDAIG	Baseline	SHIELDAIG 33/11kV Transformer	0.36	2023/24		x	x	x	CV1
SHEPD	No	297/SHEPD/LRE/STRICHEN	Baseline	STRICHEN 33 kV Circuits	0.91	2023/24, 2026/27	x	x	x	x	CV1
SHEPD	No	300/SHEPD/LRE/TIRORAN	Baseline	TIRORAN BRIDGE 33/11kV Transformer	0.02	2023/24	x	x	x	x	CV1
SHEPD	No	301/SHEPD/LRE/TRESSADY	Baseline	TRESSADY 33/11kV Transformer	0.36	2026/27	x	x	x	x	CV1
SHEPD	No	387/SHEPD/REGIONAL/SHETLAND	Baseline	SHETLAND Wider Works	2.14	2024/25	x	x	x	x	CV1
SHEPD	No	304/SHEPD/LRE/GRUDIEBRIDGE	Baseline	GRUDIE BRIDGE 11kV Circuit Breakers	0.14	2023/24	x	x	x	x	CV3
SHEPD	No	N/A	Baseline	Proactive Cut-out Replacements - SHEPD	[redacted]	2023/24-2027/28	N/A due to programme of works				CV2
SEPD	No	N/A	Baseline	Proactive Cut-out Replacements - SEPD	[redacted]	2023/24-2027/28	N/A due to programme of works				CV2
Total					**393.1**						