LOAD RELATED EXPENDITURE

Re-Opener Submission

Core Narrative

January 2025

Scottish & Southern Electricity Networks

CONTENTS

ABOUT SSEN DISTRIBUTION

Who We Are

SSEN Distribution (SSEN) is responsible for the operation and maintenance of the electricity distribution networks north of the central belt of Scotland and across central southern England. Through our two licensed electricity distribution network areas, Scottish Hydro Electric Power Distribution (SHEPD) and Southern Electric Power Distribution (SEPD), we deliver power to over 3.9m homes and businesses, with over 106,000 substations and pole-mounted transformers and 130,000 km of overhead lines and underground cables across one third of the UK land mass.

We serve some of the most diverse and unique geographies across the UK, and keep customers and communities connected whilst developing the flexible electricity network vital to achieving net zero. Our network serves some of the UK’s most remote communities and also some of the most densely populated. Our two networks cover the greatest land mass of any of the UK’s DNOs, covering 72 local authority (LA) areas and 75,000km^2 of extremely diverse terrain.

Our core purpose is to power communities to thrive today and create a net zero tomorrow. We have a responsibility to supply customers with safe and reliable power, allowing them to focus on the things that matter most, while we work hard to build a smarter, flexible, greener network that’s fit for the future.

SSEN is part of SSE, is one of the largest companies in the UK, FTSE listed company that operates across the energy sector and its activities and investments contribute around £9bn to the UK economy every year. SSE’s vision is to be a leading energy company in a net-zero world. As one of the UK and Ireland’s leading generators of renewable energy and one of the largest electricity network companies in the UK, sustainability and climate action are at the core of our business strategy. As such we see ourselves as driver of sustainable growth in the UK and key partner of the UK Government in delivering its program. SSE Plc is grounded in strong ethical principles, which translates to us doing the right thing as we undertake business. Examples include our commitments to the Fair Tax Mark, being a Real Living Wage, Hours and Pensions employer, meeting science-based carbon targets and empowering people to speak up against wrongdoing in our Whistleblowing Policy.

EXECUTIVE SUMMARY

Context

We welcome the opportunity to submit our Load Related Expenditure (LRE) approach that enables capacity for timely connections supporting growth and Net Zero within this January 2025 re-opener window. As policy for Net Zero such as Clean Power 2030 (CP2030), the National Infrastructure Commission (NIC) reviews, and price control methodologies develop in a changing political environment, it is important that we can make timely investment decisions on building Distribution Network capacity with the information available at the time. If these decisions are delayed by contextual uncertainty and result in no firm commitment on capacity expenditure, that will inevitably lead to customers not being able to connect and decarbonise their businesses, harming economic growth resulting in Net Zero targets being missed. This submission sets out our approach to dealing with uncertainty, evidences the need for additional investment within the RIIO-ED2 timeframe, and clearly outlines our decision-making process.

Since submitting our RIIO-ED2 Business Plan to Ofgem, and during the first two years of the price control, we have seen a step change in capacity requirements on the network. This is from a combination of Access SCR (Significant Code Review) driven connection schemes; ED2 network compliance schemes (as forecast under the Consumer Transformation (CT) Distribution Future Energy Scenario (DFES) scenario); and larger schemes which we need to start in ED2 to complete them in ED3. One key change is the need to invest at the 132kV/33kV Bulk Supply Point (BSP) level on the network to deal with network constraints forecast in early ED3, where project delivery times are nearer seven years rather than three, and require costs to be committed well in advance of commissioning.

We need to be able to make investment decisions now so that delivery within ED2, and the start of ED3, is physically possible, including:

- growing the skills and contracting capacity to deliver projects on site, given increase in demand for these skills nationally and globally due to wider electrification for decarbonisation;
- procuring land and acquiring planning permission, processes that take well over a year; and
- procuring long-lead plant and equipment in a competitive global environment (some of which has lead-in times of over 100 weeks).

Delivery of these schemes is critical to ensure we can connect customers and are on track to meet Net Zero and CP2030 targets and forms part of our plan to enable an optimised energy system.

For our ED2 submission to Ofgem, SSEN originally modelled our investments on the CT DFES as supported by stakeholders. However, since allowances were set across all DNOs on the System Transformation (ST) DFES scenario 2020 during RIIO-ED2 Final Determinations, this resulted in lower allowances that Ofgem could later adjust through the LRE re-opener uncertainty windows, where additional need was demonstrated.

[redacted] This is supported by an increased needs case evidenced by increases from 2020 to 2023 DFES forecast load assumptions, accepted connections and the change in policy through Access SCR. This change enables a proactive approach to upstream reinforcement, socialising costs enabling efficient network development for the benefit of all customers, rather than reacting to customer need by building the minimum scheme that was suited to historic low load growth.

Our 2020 DFES predicted that there would be between 150,000 and 200,000 EVs connected to our system in 2024, however the actual number is almost double (between 350,000 and 400,000). For heat pumps in our SHEPD area the forecast in 2020 was between 20,000 and 30,000 but in 2024 that number was between 40,000 and 50,000. Connections requests for decarbonising industries for large point loads have materialised in the past three years, that were not predicted by the 2020 DFES, including, ports, distilleries and large manufacturers. Additionally, there has been the rise of the Data Centre, a previously unpredicted phenomenon, with loads requested in some cases equal to the entire load of a current Grid Supply Point (GSP). For generation there has been an increase in the number of accepted generation connections by 74% for FY 22/23, and the number or generation projects looking to connect for CP2030 has surpassed the forecast in 2021. The impact on the network shows that actual demand in 23/24 was above ST forecast for 18% of Primary Substations in SEPD and 37% in SHEPD.

This level of increased need specifically in our SEPD area requires investment decisions to be taken now for significant upgrades at the 132kV and BSP levels on the system, where the size of the projects to deliver means a typical lead time of three to seven years, pushing some energisation dates into ED3. [redacted] he LRE allowances package encompasses the Regulation Reporting Pack (RRP) categories of CV1 – Primary Reinforcement, CV2 – Secondary Reinforcement, CV3 – Fault Level Reinforcement, CV4 – New Transmission Capacity Charges and C2 – Connections (Cost Apportioned CAPEX). The volume driver mechanism is being used to record increases in investment at the secondary level (CV2) through the annual RRP and is assumed within baseline allowance for this submission. Our forecast expenditure for the entirety of ED2 across all the above LRE categories is set out in the table below.

[redacted]

[redacted]

[redacted]

As such we welcome Ofgem's review of our submission and seek approval that Ofgem will allow reasonably incurred expenditure for load.

[redacted]

[redacted]

Overall across the SSEN licence area [redacted] we will release [redacted] capacity to enable connections, decarbonisation and drive economic growth.

Our ED2 load related project plan has been revisited in the light of the increase in volume and size of accepted connection requests. For example, data centres have used up capacity that had previously been assumed to be available for businesses, EV and HP growth. In these cases, the result is that the entire load plan for the relevant BSP needed to be revised to ensure that we were delivering enough capacity to enable both the datacenters and the load growth. Informed by stakeholders, we have developed our Strategic

Development Plan (SDP) approach for providing a modular blueprint of capacity intervention options to meet Net Zero by 2050 for each Grid Supply Point (GSP). Our approach enables clarity on investment priorities for the next price control as well as within ED2. This submission demonstrates example investment cases that support this approach. Expenditure has been built for this submission on a project-by-project basis, with each Engineering Justification Paper (EJP) displaying the range of options considered to rectify the constraint, the flexibility options available and the chosen option for deployment into delivery. The Strategic Development approach forms a policy framework that protects consumers by ensuring the right level of investment is made on the system at the right time to ensure capacity is on track to meet 2050 Net Zero. The SDP approach is compatible with the current trajectory for tRESP, and we believe adoption of this approach, would be able to underpin the trend for investment within the ED3 price control period.

To support our submission at this time, we have selected a range of 10 EJPs to be assessed for approach and support for our decision-making framework. The EJPs showcase sizing assets to 2050, where that is the best option and using a staged build approach where appropriate. This has included revising schemes from our ED2 business plan submission to align to the updated customer needs and align to our SDP view by GSP for the long-term development of the network. We are requesting Ofgem to endorse our SDP approach and the optioneering methodology for identifying the preferred solution within our selection of EJPs. We will also utilise this approach in the development of our ED3 plans, subject to validation at Regional Energy Strategic Plan (RESP) level and this means that when we submit the full funding request at the next re-opener window, the methodology will have already been endorsed.

Our agreement to the ED2 settlement was based on the understanding that Ofgem had built mechanisms into the price control that would deal with the uncertainty presented by a rapidly decarbonising environment.[1] During this time, Ofgem's own governance has been adjusted to include the 'Net Zero Duty' and the 'Growth Duty', reflecting both the dynamic policy environment in which we are operating and the criticality of network infrastructure to delivery of a low carbon, high growth economy. Our SDP methodology works to create short-term, efficient certainty in the context of long-term uncertainty, protecting customers and ensuring a focus towards Net Zero 2050. The flexibility afforded by the ED2 framework facilitates application of our SDP approach, which will likely form the base of submissions for ED3 and beyond during this period of growth. This will also mitigate against the threat stop-start nature of price controls and the lack of continuity this can encourage.

Content of submission

In this Load Related Expenditure (LRE) January 2025 'Part 1' re-opener submission we set out the expected costs to enable agreement to be reached on the funding that will be asked for in the next additional LRE UM re-opener window that Ofgem will direct. We have considered the timing for a future LRE re-opener window and have assessed that **October 2025** is the most suitable time for that window, since it would provide sufficient time for Ofgem to review our full submission and decide on any funding within a reasonable timeframe (by no later than March 2026) to facilitate efficient delivery of these schemes within ED2. [redacted][2] This investment is essential for delivery of Net Zero and Clean Power 2030, and we will be working at considerable risk, contracting with partners for delivery of projects for which we do not currently have Ofgem's agreement for funding. Whilst we acknowledge the ability to forecast costs through the Price Control Financial Model (PCFM) and recover costs through revenue, due to the level of quantum, we are asking for increased confidence that Ofgem is comfortable with our needs case approach for the additional expenditure. We have built an assessment of deliverability into our submission and have used this as part of the calibration of the size of the ask.

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1 p. 16, RIIO-ED2 Final Determinations Core Methodology Document, 30 November 2022, [RIIO-ED2 Final Determinations | Ofgem]

2 Costs specified throughout this submission are in 2020/21 prices to align with the original RIIO-ED2 price base, unless otherwise noted.

We are considering future needs out to 2050 to ensure interventions undertaken in ED2 will be developed to meet longer term requirements in an efficient manner. UK decarbonisation goals are clear, as most recently outlined by CP2030, and at SSEN Distribution we don't want to be a blocker to that ambition.

In preparing this submission we have taken the approach that, where we can size for 2050 now, at low incremental cost, we should. In many cases, our EJPs set out large programmes of work at our GSPs (Grid Supply Points) where we are taking the first steps towards that today, through a modular approach to build towards the 2050 solution. This is evident in some of the more reactive needs driven work required now to connect customers. In many cases, we are taking a staged approach to release capacity required now, utilising flexibility in the short term with a clear plan to build the 2050 solution. For example, completing low regret work on site to allow us to mobilise the next stage of the 2050 solution quickly in the future.

This approach to load related expenditure reflects the themes that run through Ofgem's RIIO-ED3 Framework Consultation, where Ofgem noted that there is an increased demand and a greater reliance on electricity for essential services. Our approach is in line with Ofgem's expectation that DNOs need to take a "proactive, risk-based approach to future proofing their networks."[3] This also supports Ofgem's desire for DNOs to be "ready with the necessary capacity, to meet decarbonisation goals at least cost, based on whole system value."[4] The longer-term view that we are taking with our investment approach is aligned to Ofgem's view on Networks for net zero – "strategically planned network investment, providing capacity and access for users when it is needed at least cost based on whole system value for current and future users."[5]

Our approach in this re-opener is an early example of how the regulatory framework can be adaptive and responsive to change and enable a multi-staged approach to investment decision making at distribution level. This can allow the early application of a progressive approach underpinned by the SDP methodology, which can be used as the basis for submissions for ED3. Even within a policy environment that is continuing to evolve, this is the next step to help build certainty and enhance deliverability in the context of the significant step-change required to deliver net zero.

Conclusion

Our proposed uplift in LRE expenditure [redacted] will release [redacted] capacity to enable connections, decarbonisation and drive economic growth.

We are asking Ofgem to review and endorse our Strategic Needs Case approach as part of the LRE re-opener window in January 2025 to give us confidence to mobilise this work at financial risk. This will allow us to start to mitigate supply chain and resourcing risks that are currently a feature of the marketplace, driven by increased demand driven by electrification investment across the UK and globally. This is also an opportunity to give clear signals to the supply chain, by providing a committed look ahead encouraging skills investment, which can then be built on into ED3 enabling continuity across price controls. Since this requires a significant financial commitment for us, we are seeking support from Ofgem, for us to proceed with this approach.

It is positive that Ofgem has agreed to review our January 2025 LRE UM submission, and we believe that this will simplify the assessment of further LRE UMs in the forthcoming directed additional window driving growth. The endorsement of the approach set out in this UM, would also set a clear framework for LRE network investment into ED3, subject to validation by the RESP, facilitating timely delivery of CP2030.

We are seeking the following from Ofgem:

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3 p. 7, ED3 Framework Consultation, Ofgem, 6 November 2024

4 p. 7, ED3 Framework Consultation, Ofgem, 6 November 2024

5 p. 21, ED3 Framework Consultation, Ofgem, 6 November 2024

a) a written response with a view on, or acceptance, of our approach to releasing capacity by August 2025 based on the sample set of EJPs, including whether the level of justification provided meets requirements fully or partially;
b) a written commitment by August 2025 that reasonably incurred expenditure will be allowed for developing load schemes and that this expenditure will be treated separately in RIIO-ED3 benchmarking to avoid penalizing companies that have spent money developing load schemes;
c) a written response by August 2025 that based on the evidence provided it is fully/partially satisfied that the procurement and delivery approach are in line with best practice and will deliver value to customers;
d) a direction for an additional LRE UM re-opener window in October 2025;
e) a commitment from Ofgem to assess the expected October 2025 submission in accordance with Ofgem's assessment from January 2025 and;
f) a commitment to provide a decision against the October 2025 submission by no later than March 2026.

This is needed for us to commit the required investment to deliver the identified 132kV and EHV reinforcement schemes that will enable load and generation growth and connections and ahead of forecast constraints and make an investment in capacity [redacted] in the UK economy within the ED2 price control. The alternative would be lack of growth, the inability to confidently secure the supply chain through stop/start regulatory frameworks, and restrictions and lack of confidence in growing the required skills base.

1. ALLOWANCE ADJUSTMENTS

Approach to January 2025 and subsequent re-opener window submission

Based on discussions with Ofgem between August 2024 to January 2025, and having reviewed Ofgem's Re-opener Guidance and Application Requirements Document, this submission forms the *Part 1 – Overarching narrative*. It has been agreed with Ofgem that we should submit this suite of documents as a Strategic Needs Case. We are seeking Ofgem endorsement of the approach that we are taking to investment, including for SSEN to progress development of the schemes in Appendix 2. A sample set of 10 EJPs has been included to provide Ofgem with the opportunity to review and endorse the general engineering approach that we have applied to the full set of schemes which will comprise our submission in the next additional LRE UM re-opener window that Ofgem will direct.

Our submission in the next additional LRE UM re-opener window that Ofgem will direct will form the *Part 2 – Project specific justification papers*, where we will request funding based on forecast delivery at that point.[6] As part of this submission, we are also seeking a commitment from Ofgem to assess *Part 2 – Project specific justification papers* in the next additional LRE UM re-opener window that Ofgem will direct, in accordance with Ofgem's assessment of Part 1 of our submission.

By following Part 1 and Part 2 of the LRE guidance in this way, it removes the need to define bespoke criteria for Ofgem's assessment of our submission. As part of the engagement process ahead of submission, Ofgem confirmed that they will assess Part 1 of our submission of the LRE re-opener as noted above. This will be approached as a Strategic Needs Case submission.

The sample EJPs have been selected to reflect a mix of project types and approaches. This is to enable Ofgem to assess our application of our approach to Load planning, and subsequently endorse our approach, or provide feedback on aspects which we should further consider prior to our submission in the next additional LRE UM re-opener window that Ofgem will direct. In the interest of making a streamline submission to Ofgem we have not submitted the Cost Benefit Analysis (CBAs) associated with each EJP, nor the additional supporting tools that we have used, as outlined in Section 7: Justification of Optioneering. However, these have been completed and are available should Ofgem wish to review them.

[redacted]

[redacted]

As noted in Ofgem's RIIO-ED2 Final Determination, Ofgem's LRE approach including the two re-opener windows, was purposed to "ensure the right investment at the right place at the right time".[7] **Based on the information we have provided, we are asking for endorsement that we need to invest more than currently funded for in ED2 in order to release more capacity in the medium to long term.** [redacted] This proactive approach to investment will provide efficient costs for customers and enable earlier connections, and subsequently unlock economic growth. Since this requires a significant financial commitment for us, we require

6 pp. 44-48, Re-opener Guidance and Application Requirements Document, 17 February 2023, 17 February 2023 publication of Associated Documents and relevant issue logs.zip

7 p. 16, RIIO-ED2 Final Determinations Core Methodology Document, 30 November 2022, RIIO-ED2 Final Determinations | Ofgem

endorsement from Ofgem in a timely manner for us to proceed with this approach. Between our Part 1 submission in January 2025 and our Part 2 submission in the next additional LRE UM re-opener window that Ofgem will direct, we are seeking a written commitment from Ofgem that they will allow reasonably incurred expenditure in developing load schemes, and that they will treat this expenditure separately in the RIIO-ED3 benchmarking to avoid penalising companies that have spent money developing load schemes. This is key to ensuring we can provide an acceptable balance of risk.

2. BUSINESS STRATEGY ALIGNMENT

Sizing to 2050 for efficient Net Zero pathway

Our business strategy is focused on powering our customers and communities to thrive today and create a net zero world for tomorrow. This means we are ensuring we are set up not just for this price control and the next but have a clear pathway to 2050. This is driving change across our business, particularly around our load investment plans.

The start of ED2 coincided with the implementation of the Access Significant Code Review (SCR), which has disconnected the minimum scheme provided under DCUSA, giving the ability for the DNO to plan longer term for network growth as part of general reinforcement. This significant change in policy, and the need for businesses to rapidly decarbonise has led to an increase in connections requests over the first two years of ED2, allied with this greater policy certainty, we have developed our Strategic Development Plan approach for 2050. This means that each intervention we are taking on the network, be it for a specific connection or against background load growth is considered against a solution that delivers Net Zero by 2050 now, or forms part of a staged modular approach to that delivery.

This means that we have looked at what the network solution looks like in 2050 (based on current DFES) and have worked back from that network solution to ensure that today's investments will form part of the 2050 solution. In some cases, this can be as straightforward as sizing assets being installed now to demand levels in 2050. In other cases, it means understanding that while today we may need to reinforce an overhead line circuit ring network now, by 2050 we will need more substations on that circuit to deal with the expected increased load as it materialises. This is demonstrated through our network optioneering process, where some network designs benefit from a staged approach to accommodate future changes most efficiently.

We are developing our SDPs by area looking out to 2050.[8] Developing this approach through the first half of ED2 will allow more effective network development and transparency in consultation with our stakeholders. It paves the way to delivering net zero at lowest cost since the actions we are taking now will be part of a staged approach for the future. Our Engineering Justification Papers for the LRE Uncertainty Mechanism are developed in tandem with this approach, setting us up for robust decision making for ED3, since we will know the next step in the development plan, and can swiftly carry out implementation. This is long term, low regret, pragmatic planning.

This approach sets us up well amid a continual set of policy changes set to accelerate the energy transition through electrification. We can be agile in responding to changes from CP2030 and support the developing Regional Energy Strategic Plans (RESP) providing options from the bottom up to support top-down plans. It lays a foundation for RESPs since it provides an iterative plan for our network by GSP, which we can adapt based on new inputs. These SDPs provide a solid point of communication for stakeholders, including the NESO with the network inputs required to help build and iterate a local spatial plan to 2050.

Strategic Development Plans

To ensure that we have the right long-term approach to investment, we have embarked on setting out SDPs for all GSPs across our network. The concept of the SDP is to set out a vision for the development of the network out to 2050. The SDPs bridge the gap between the DFES and projects entering the Distribution Network Options Assessment (DNOA) process. These plans utilise the DFES and stakeholder insights from local spatial plans to translate forecasts into system needs out to 2050.

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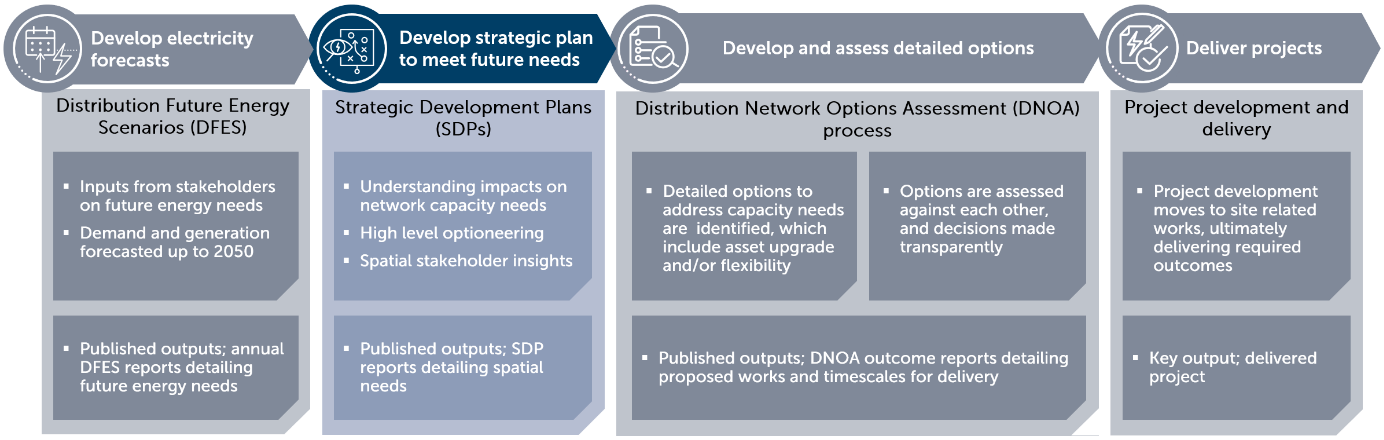
8 SSEN outlines delivery plans for huge net zero network development - SSEN; and Our strategic network planning process - SSEN.

This serves several purposes. Firstly, it ensures that the interventions we are taking today align to a longer-term plan. This is vital, as with rapidly increasing connections to the network, it can be easy to follow a reactive approach to network development. The SDPs ensure we have a strategic framework to consider the development of the network at Distribution level, and hence inform planning for the Transmission network. Our approach is to enable load growth on the Distribution network, in expectation of a rapid release of capacity at Transmission level as set out in CP2030. Secondly, it enables our stakeholders to understand the likely development of the network over time, based on what they are telling us. This provides transparency and triggers conversations with stakeholders around how their future needs might be incorporated, leading to constructive iteration of those plans. We believe this is the first step to the co-development of spatial plans at local level to deliver net zero. Finally, the timing of various investments set out in the SDPs can allow early conversations around planning, land access and land purchase. This can help ensure that when future investments are required, they can be delivered faster. This is crucial given the rapid acceleration of demand forecast for the 2030s.

By producing these plans, we deepen our understanding of our local communities and their needs across our two licence areas. This facilitates better identification of the long-term system impact that will arise from these. It also allows for a strategic view of the network development required to facilitate net zero informed by and informing local spatial plans.

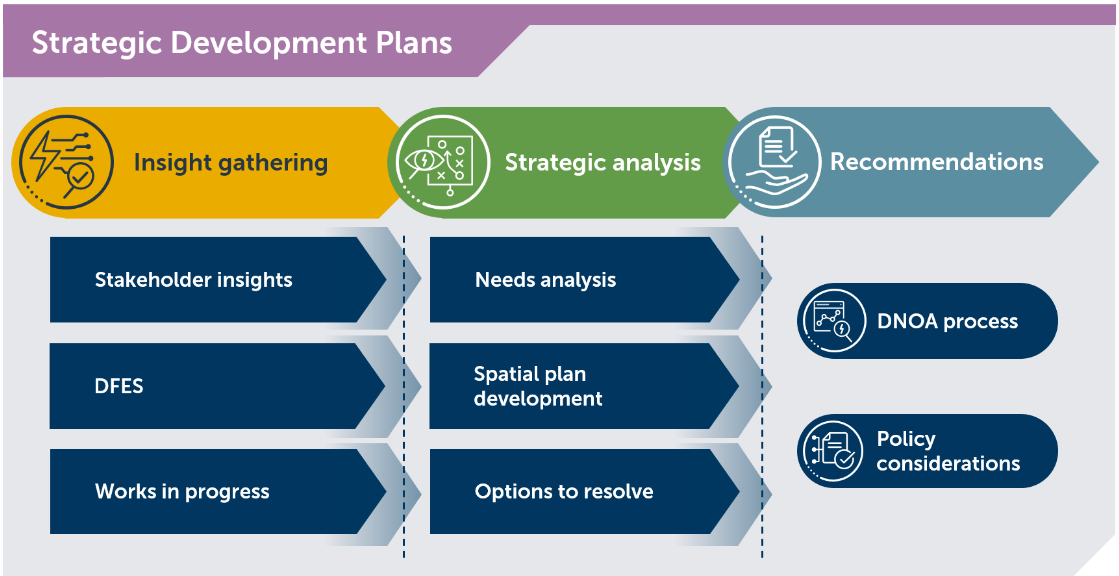
Figure 1: Process for Identifying and Developing Load Related Projects



SDPs are living plans reviewed on an annual basis as our DFES forecasts are updated, reflecting decarbonising industries and changing energy vectors. They act as blueprints to assist our connections and planning teams with the future network development. The recommendations from the SDPs allow us to respond swiftly to customer needs with works that form critical components of a long-term plan.

SDPs are published as draft for industry consultation. This includes the underlying methodology which is updated annually. Stakeholder feedback is captured through webinars, bilateral discussions and formal responses to the consultation process and then used to finalise the SDP.

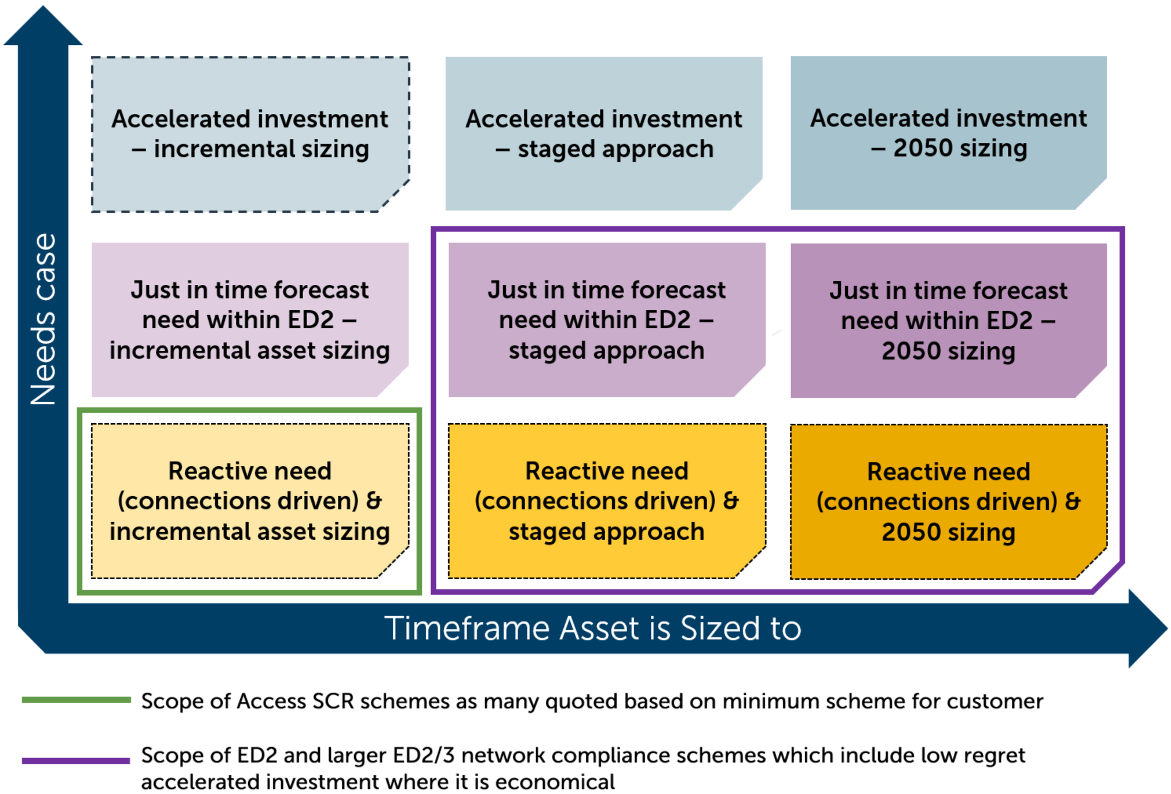
Figure 2: Process for Strategic Development Plans



Investment approach

Our needs case for investment is underpinned by the requirement to connect customers, and ensure the network remains compliant in ED2, and the start of ED3 by investing throughout ED2. Figur illustrates the timeframe for which assets are sized for the needs case of the investment.

Figure 3: Investment Spectrum



For delivery of large capital projects, there can be a long lead time from network planning (beginning with DFES) through to design, build, and energisation of assets. This process is typically at least 3-4 years and for larger works can extend to 7-8 years. This means that there are three broad options in terms of **needs case** for investment:

- **Reactive:** We only start with the planning and design process once demand has arisen (accepted connections requests). This means that customers must wait several years for a connection to meet their full capacity needs. In the short term this approach relies heavily on Access SCR (flexible connections) and broader flexibility procurement. These projects are listed in Table 4: Growth in Connections.
- **Just in time**: We use DFES to ensure that based on the lead times to release capacity, we start the process in time to release capacity ahead of the forecast constraint materialising. For example, in Appendix 2g Abernethy GSP EJP we use flexibility to ensure we are intervening at the most cost effective time to release the capacity just as it is needed.
- **Accelerated**: There are some areas where it makes sense to pull forward investment/interventions to today. This could be because it is cost effective to do more work while at site now, rather than come back in the future. It could also be from a deliverability perspective, where there is a need to start work now to get the best out of the supply chain by smoothing demand for skills and equipment.

In addition to needs case, the other dimension which needs to be considered when thinking about investing strategically is **asset sizing**. Again, there are three options for asset sizing:

- **Incremental**: The network is built out to meet the immediate demand i.e. next size up transformer. This would be the approach historically taken to quote commercial connections customers for the minimum scheme as it is usually the lowest cost way to meet a specific connection request.
- **Staged approach**: The network is built out to meet demand for next 10-15 years and further work needed to deliver capacity forecasted for 2050. This is typically where the cost of delivering the full 2050 scheme can't be justified at this point. An EJP where this approach is used is Harvard Lane, because the wider network needs to be taken into consideration when delivering the optimal solution and rationalising the 22kV parts of our network
- **Sized for net zero**: This is more akin to touch the network once, where assets can be immediately sized for 2050 at an economic incremental cost. This is most effective for single assets being installed e.g. Transformers, subsea cables. An example of this is in Appendix 2h Burghmuir GSP EJP where a 33kV circuit reinforcement option is selected.

There are three broad categories of projects that we are looking to submit a needs case for, which cut across these categories of investment:

1. **ED2 network compliance schemes**. These are forecast under CT scenario, with DFES load growth layered onto the existing demand and contracted demand. There risks being network compliance issues within ED2 if the associated work is not undertaken. This represents the sample set of EJPs that are referenced in Table 16: EJPs to Demonstrate Investment Approach.
2. **Schemes which need to start in ED2 to complete in ED3**. These schemes have long lead times for larger works which we can see are needed in ED3. If not undertaken in ED2, for these projects there would be network compliance issues in ED3 and/or delays to connection in ED3. Details of these schemes can be found in the project list Appendix 2.
3. **Access SCR schemes**. These are connection applications that trigger investment within the price control. Implications of not undertaking this work now is that customers would be unable to connect to the network, and the summary of these schemes is in Table 4: Growth in Connections.

Planning amidst uncertainty

Our network planning is based on our DFES. Applying these to our network and assessing where interventions are required over different timeframes forms the basis of our investment strategy. The DFES represents a range of potential demand and generation growth scenarios based on a coherent set of assumptions produced by the NESO in its Future Energy Scenarios (FES). We then take the national FES and disaggregate them to local level on the Distribution network. This disaggregation uses a range of drivers, including social-economic and housing stock, allied to specific engagement from our customers and stakeholders to provide a forecast of demand at each of our substations, right down to LV.

The DFES provides the basis of our system modelling and planning and is set up across four different planning assumptions. Against the timeframes for designing and delivering large infrastructure projects, the background to forecasting is continually iterating. We have taken an approach whereby the EJPs are primarily driven by the CT scenario from the DFES that was published in 2023, as this scenario is likely to deliver Net Zero. CT was the baseline scenario used for our original ED2 business planning (modified to ST for consistency in the Ofgem Final determination of allowances). We believe this scenario strikes the best view of future requirements on our network and is closest to expectations for CP2030.

As indicated above, many of the drivers for our proposed schemes are connections requests which have materialised recently and can’t be facilitated without interventions. For these schemes, uncertainty over future demand growth based on DFES plays a role in understanding how to size any assets, or the amount of flexibility to procure. To ensure that we have this network sizing correct, we have carried out sensitivity review of schemes against the more aggressive Leading the Way (LtW) scenario. This provides a check as to whether the proposed scheme would be robust under a higher growth scenario. This check is undertaken for projects where we are sizing for net zero, so capacity being released is sufficient to meet 2050 demand under all scenarios, including LtW. Sensitivity analysis has also been carried out where there is a significant spread across the scenarios in lower growth forecasts, and this is evidenced in Culloden and Bermerton EJPs.

Where we find that under a higher load growth scenario, we would make a different, more costly investment, we are undertaking further analysis to assess what the optimum decision would be. This is based around an assessment of regret, as highlighted in Table 3.

Table 3: Framework for considering regret

Outturn scenario	Strategy 1: Invest for CT	Strategy 2: Invest for LtW
Consumer Transformation	1. No regret	2. Regret = the incremental investment costs for LtW which turn out not to be required
Leading the Way	3. Regret = the delay in facilitating connections if LtW materialises plus the additional costs of accommodating those connections once they materialise	4. No regret

In the example above, the analysis effectively compares regret across outturn 2 versus outturn 3. To support this, we have developed what we call the Strategic CBA tool. This is explained in more detail in the section below. Each EJP has a section which highlights the outcome of this analysis and how that has influenced our intervention strategy.

Strategic CBA

The current distribution planning process uses two standard CBA tools:

- A deterministic CBA to ensure delivery of the most efficient network intervention;
- The Common Evaluation Methodology (CEM) that assesses whether flexibility could deliver additional capacity more efficiently.

There are two main limitations to this approach:

- The tools take a deterministic view that fails to consider uncertainty in future network load;
- There are a limited number of benefits that can be accounted for.

A more strategic approach to network investment needs to overcome these limitations. We have done this through enhancing a third industry standard tool, the Whole System CBA, to both take a least worst regrets approach to strategic investment and consider broader benefits. The Whole System CBA is already used in Ofgem's Coordinated Adjustment Methodology (CAM), and we are building on an already scrutinized tool. We refer to this enhanced tool as the Strategic CBA.

The Strategic CBA leverages the Social Return on Investment (SROI) framework developed by the ENA. It can help identification of the optimum timing of an intervention by considering requirements under multiple DFES scenarios. It can also consider the size and scope of solution required, i.e. whether there is benefit on a broader more strategic solution implementation rather than an incremental approach. This is demonstrated in an EJP such as Bremerton because the different scenarios forecast dates at which the network becomes non-compliant that are five years apart from one another.

Application of flexibility

Flexibility Services are always considered as one option for resolving the identified network need, where it is a cost-effective solution. Our Flexibility First approach, using Flexibility to optimise the timing of Network Reinforcement for 2050, ensures all use cases are assessed for the use of Flexibility Services. When we are doing our load related expenditure assessment, we focus on the use of Flexibility Services, as the use of different connection products, such as Curtailable Connections and Ramped connections have already been captured during the connections process. We see Flexibility as a key tool in supporting the development of our network and helping manage the uncertainty in deliverability and connecting customers more quickly.

The aim of the assessment is to utilise Flexibility Services where we identify direct benefit to consumers and where we are likely to be able to procure the required volume of services. This is evidenced in the flexibility section of our EJPs, where most of the solutions employ flexibility to optimise the timing of reinforcement work.

Our flexibility procurement strategy considers the expected market liquidity; the time to deliver the reinforcement and the uncertainty of demand growth in the region.[9] Where we expect procuring flexibility services to be particularly challenging and we have long lead times for delivery. Which areas we are procuring is published as part of the SLC31E Procurement Statement and ahead of the individual bidding windows being used.

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9 Please refer to our SLC31E - SSEN 2024-25 Flexibility Services Procurement Statement and Flexibility Services Procurement - SSEN for more detail.

DNOA approach

The Distribution Network Options Assessment methodology (DNOA) ensures that we compare technical solutions with flexibility options through utilizing the industry standard Common Evaluation Methodology (CEM) CBA tool.

The DNOA methodology is consulted on annually with the most recent version is published on our website.[10] We apply the DNOA methodology to our load related needs to produce a series of DNOA outcomes which are published quarterly as DNOA outcomes reports.

Our DNOA decision-making process sits within the overarching Strategic Planning process. We have introduced proportionate measures at the appropriate step to facilitate decision-making, manage conflict resolutions and increase transparency to our stakeholders. All EJPs included within this submission have been evaluated through the DNOA process.

Figure 4: EJPs Demonstrating Approach

No	EJP	Flexibility Enabled	Sizing to 2050	DFES Scenario Analysis Strategic CBA	Staged Approach	SDP Developed	DNOA published	Transmission Enabled	Complete in ED2	Revised ED2 scheme
1	Abernethy	✓			✓		✓	✓	✓	✓
2	Culloden	✓	✓	✓			✓	✓	✓	✓
3	Keith		✓				✓	✓	✓	✓
4	Burghmuir	✓	✓				✓	✓	✓	✓
5	Cowley Local Main and Rose Hill Network	✓			✓	✓	✓	✓		✓
6	Southampton BSP RBB and associated 33 kV network	✓			✓		Due to publish Feb 25	✓		
7	Harvard Lane	✓	✓		✓	✓	✓	✓		
8	Denham BSP	✓	✓			In progress	✓	✓		
9	Bemerton 33kV Network	✓	✓	✓			Due to publish Feb 25	✓		✓
10	Uxbridge				✓		✓	✓	✓	✓

10 ssen-dnoa-methodology-final-march24.pdf

3. DEMONSTRATION OF NEEDS CASE

DFES changes from ED2 submission

For our ED2 submission, we 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. As part of the ED2 settlement, Ofgem's allowances for ED2 are most closely aligned to the ST DFES scenario, which was highlighted as unlikely to deliver net zero. We defined load related reinforcement works required under this scenario, and ensured these were also required under the more ambitious CT and LtW scenarios. This was our test for high certainty of need, as these projects were required under all Net Zero compliant scenarios according to our 2020 DFES.

Our submitted BAU expenditure was based on the DFES ST scenario over the five-year period, however it included additional expenditure to cover the requirements of the CT scenario. The expenditure covering CT need was removed by Ofgem at Final Determination and our proposed allowance was reduced to align to the ST scenario only. This was accepted by SSEN with the knowledge that there were two re-opener windows available to manage the uncertainty inherent in forecasting load flows on the network.[11]

This additional expenditure, over and above ST, associated with delivering our investment in accordance with CT in these first two years of the period was £23m and would have ensured the early and timely establishment of the capacity (supply chain, people and network) and ability required to deliver to CT throughout ED2. Although this was not included in our allowances following Ofgem's Final Determinations, we were confident that we would be able to use both uncertainty mechanism windows in January 2025 and January 2027, as outlined by Ofgem in the SSEN Annex to the RIIO-ED2 Final Determinations.

To give visibility of our view of a net zero trajectory we also proposed a third category of expenditure that would be funded solely through the LRE UM. Our estimate of this category of expenditure, at the time of business plan submission, was estimated to be £188.3m[12], and this paper sets out the changes we have seen since then, and the approach and evidence to justify further investment [redacted] over the remainder of the ED2 period.

In comparison to the 2020 DFES used for our ED2 submission, we have found the variability across scenarios has reduced considerably in our latest 2023 DFES, which aligns with NESO's 2023 FES. This range is expected to narrow further with NESO's FES 2024 Pathways.[13] We consider the CT scenario as our best view within the 2023 DFES, and this has been used within our various regulatory reports throughout 2024, within our SDPs and EJPs. As this scenario relies primarily on electrification rather than widespread adoption of hydrogen for decarbonisation, we estimate the CT scenario will align closely with the Electric Engagement (EE) pathway of the 2024 FES.

Figures 5 and 6 below show the comparison of forecast LCT volumes for 2024/25 in each DFES iteration, against actual connected volumes. Overall, EV numbers continue to grow significantly in both licence areas, especially in SEPD where this is ahead of the national average. With the ST scenario, Heat Pump

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11 p. 16, paragraph 3.9, RIIO-ED2 Final Determinations Core Methodology Document, 30 November 2022, Ofgem, RIIO-ED2 Final Determinations Core Methodology. Emphasis added. "We have reduced LRE allowances from those proposed in our Draft Determinations by £188m to reflect consultation feedback on our cost assessment methodology. This ex ante allowance is calibrated using various parameters, including adjustments of some elements to match a net zero compliant Future Energy Scenario (FES), System Transformation, for LCT uptake. **However, we have implemented a package of UMs that will enable networks to invest immediately and without administrative burden if LCT uptake exceeds this scenario**."

12 A_10.1_Load_CLEANFINAL_REDACTED.pdf

13 https://www.neso.energy/document/321041/download

projections have reduced slightly in SEPD but increased in SHEPD. The reduction in HP numbers is reflective of the slow rate of uptake across the country. Due to the higher percentage of off-gas buildings in SHEPD compared to the GB average, the adoption of heat pumps is expected to accelerate above the national trend, especially in areas where off-gas buildings are common.

Figure 5: Electric Vehicle volumes 2024/25 forecast vs actual

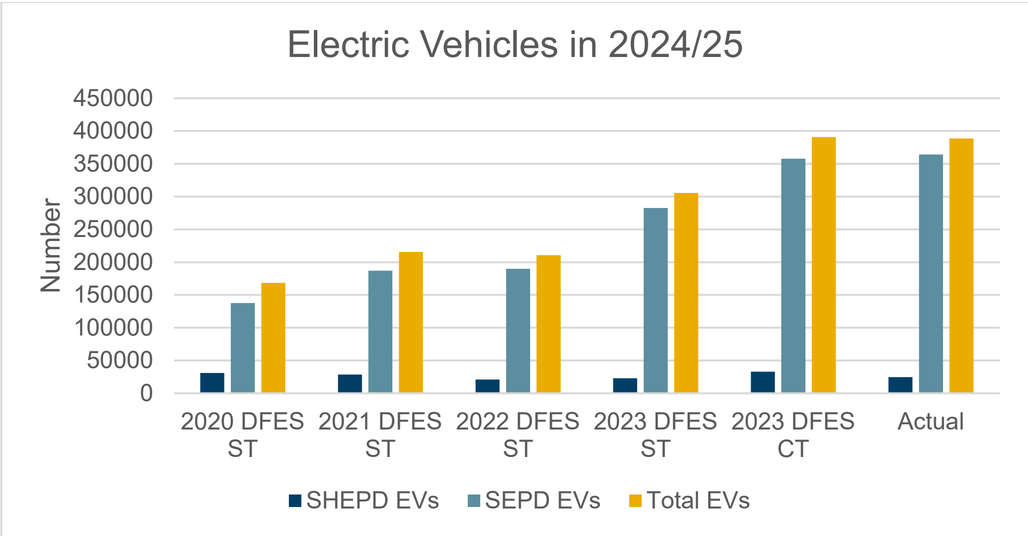
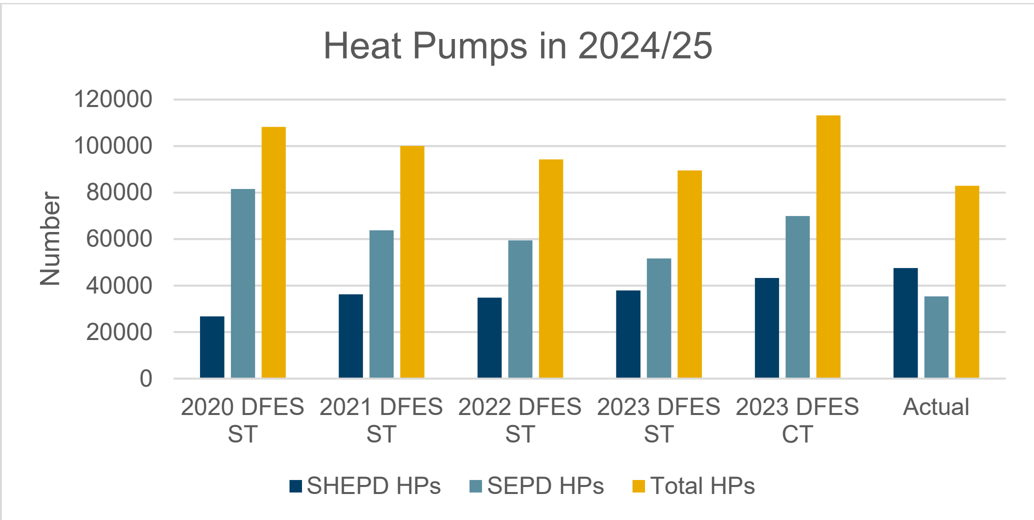


Figure 6: Heat Pump volumes 2024/25 forecast vs actual



From these figures, EV actuals are significantly higher than the 2021 FES/DFES projections that allowances were in-part set against, and HP actuals are lower by approximately 17,000 units. It should be considered however that we have just started Q4 of the 2024/25 year, and these numbers will continue to increase.

Additionally, we are experiencing increased engagement and connection requests from industries that are decarbonising, including whiskey distilleries, ports, data centres and manufacturing, which are creating significant point loads in some of our most remote and least interconnected areas. Overall, [redacted]

Growth in Connections and Connections Access Charges

Over the last four years we have seen an increase in the number of applications and accepted quotations to connect renewable generation, concentrated around hybrid projects, which consist of energy storage combined with other technologies and solar as result of the geography and planning conditions. The number of generation projects looking to connect for 2030 has considerably surpassed our forecast in 2021 which supported network strategic development and our ED2 submission, pointing to the need for reform of connections. This includes the increase in the number of accepted generation connection offers by 74% in FY 22/23, with continued increases in subsequent years. This remains the case even with the backdrop of delays for Distribution connections to complete because of dependency on Transmission constraints and Transmission network reinforcement works.

Table 4: Growth in Connections

[redacted]

[redacted]

One of the key changes at the start of ED2 was the introduction of new Access arrangements through the Access Significant Code Review. This is particularly impactful for new demand connections and is why we have needed to look at these connection requests in the context of our overall plans for network reinforcement within our EJPs. The reduced financial costs to our customers from the changes within the new arrangements have also helped to drive an increase in the number of connections requests that have been received since the start of ED2. The speed of decarbonisation via electrification has accelerated driven by industry, and the rapid digital transformation is driving new increased in demand.

To better understand the accelerated demand growth, we have developed relationships with key stakeholders, including decarbonising industries, to understand their future plans. This means we can build a distribution network capable of facilitating local development plans including the uptake of low carbon technologies, which will ultimately allow us to align with the UK's wider net zero ambitions.

We have established a team of engagement specialists to support this data gathering exercise, including information from LAs in the form of Local Area Energy Plans. These insights form a bedrock for our strategic planning process and allow us to strategically plan our network ahead of need.

However, we have also recognised that a portion of the demand growth across our license areas is not necessarily driven by an ambition to meet net-zero. The increased uptake of data centre connection applications driven by an increased demand for advancing technologies such as the use of Artificial Intelligence (AI) is a key example of this. We have incorporated this understanding into the solutions proposed in our EJPs by developing a network that will make it easier for us to facilitate unforeseen large connection applications without impacting the uptake of low carbon technologies.

In the West London area of our SEPD license, in collaboration with the Greater London Authority, NESO and NGET, we have set up an innovative approach, using a ramping agreement with key connecting customers to enable developments to connect earlier than would otherwise have been possible. This is allowing a manageable ramp rate of demand (such as low carbon technologies) on local HV networks that were previously limited by transmission network constraints.

Impact on the network

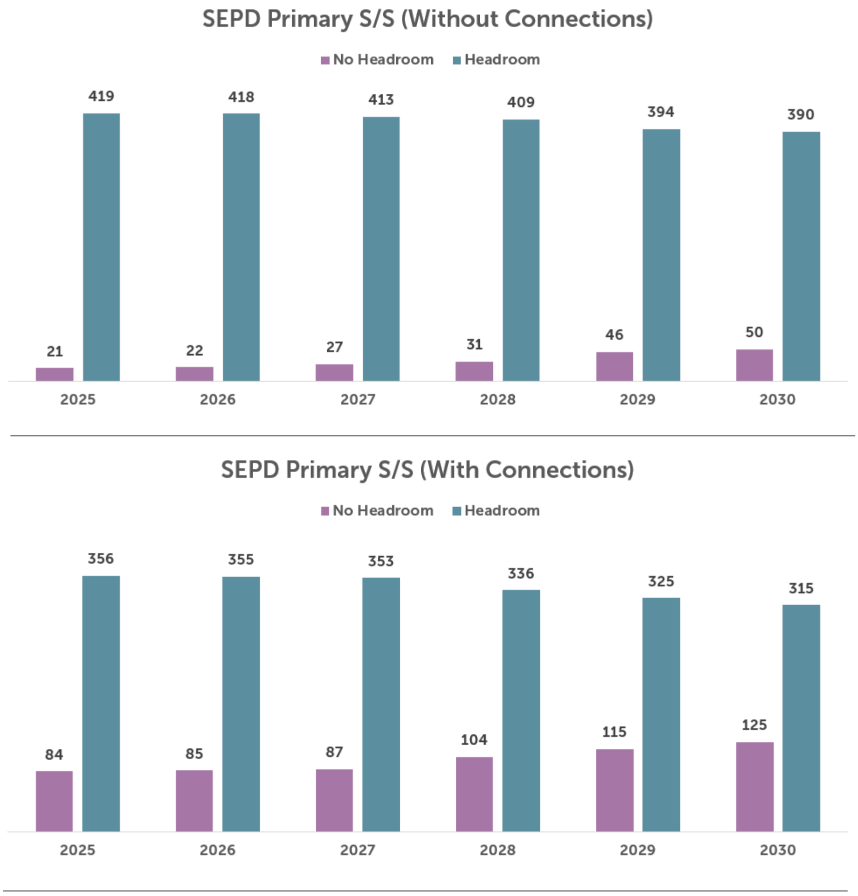
Our baseline allowances were determined on the 2020 ST DFES scenario at time of business plan submission, and the 2021 ST DFES scenario was used by Ofgem for benchmarking. Since then, our analysis has shown that our 2023/24 actual demand is above the 2021 ST forecast, for approximately 18% of our substations within SEPD, and approximately 37% in SHEPD. This comparison was drawn from the load figures used within our 2022 Network Development Plan (NDP) submissions against our 2024 RRE2 tables.

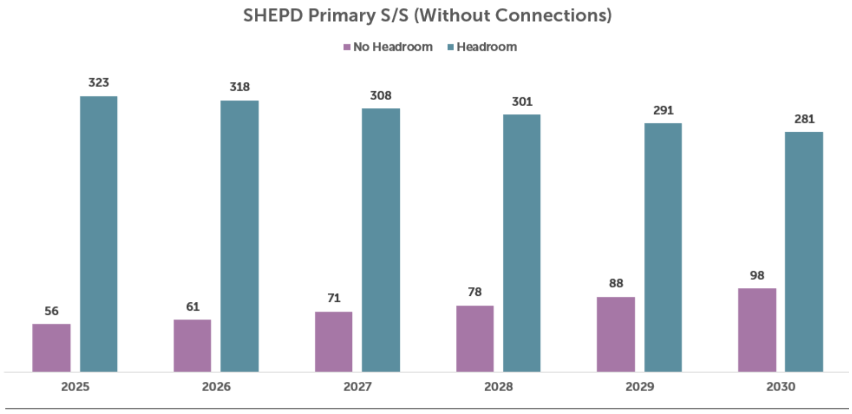
We attribute this increase mainly to an increase in LCTs and to large demand customers, which have connected to our network since ED2 Final Determinations. We have a robust DFES methodology that seeks inputs from a variety of stakeholders, however large commercial demand needs that LAs are not aware of, are often difficult to predict without targeted engagement to wider commercial industry.

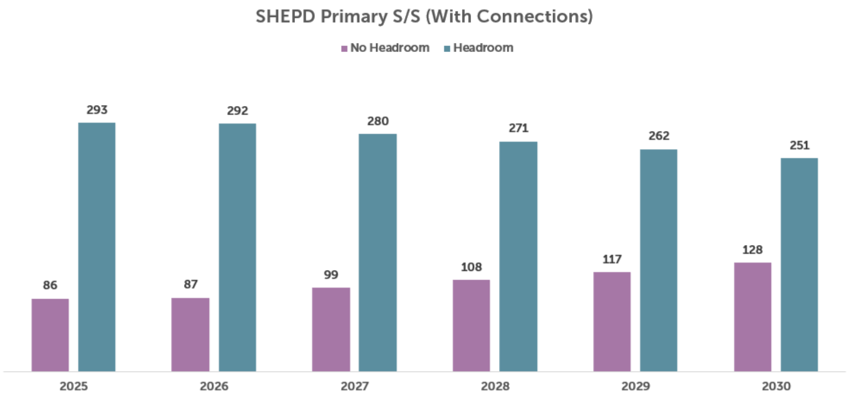
We are aware of this challenge and have taken action to address over the past year. Our engagement specialists have taken action to reach out to commercial stakeholders and better inform future projections. An example of this is our recent work to engage with whisky distilleries across Scotland, to provide a better view of their plans to electrify production. This approach will allow us to understand customer needs earlier and build these into our forecasts if they come with a high degree of certainty.

The demand increase is in certain locations, rather than being spread across all parts of the network. However, given the increased number of demand customers not yet connected, it is likely this will affect more substations as we progress through RIIO-ED2. [redacted].7 below shows the projected number of substations overloaded with contracted connections not included and included respectively. If further action is not taken to address this visible growth in connections, network headroom will continue to reduce, creating a potential barrier for net zero requirements.

Figure 7: Network capacity taken from 2024 NDP







Differences between Licence Areas

At SSEN, we operate and maintain two licence areas: in the north of Scotland (SHEPD) and south of England (SEPD). In SHEPD, historically there have been many areas which have been compliant under P2/8, as their demand has been less than 1 MW. However, as these rural areas become increasingly reliant on one source of power for both heating and transport, and as load increases this results in the necessity for increased investment to ensure continuity of supply and realistic restorations times, which drives the wider compliance with P2/8. Since our ED2 submission Access SCR has changed the way that connections are managed on our network, with a particular impact on SHEPD where many of the demand connections are now below the requirement for cost apportionment.

The SHEPD licence area covers 25% of the UK land mass with 10% of the population and have over 100 subsea cables linking the key island groups of the Inner Hebrides, Western Isles, Orkney and Shetland. Distances between generation and demand centres are much larger than in the South, meaning that keeping the system within limits of Voltage is often more challenging than thermal limits. We are also undertaking our Hebrides and Orkney Whole System Uncertainty Mechanism (HOWSUM) programme at the same time to increase resilience to island communities, while enabling decarbonisation.

HOWSUM is an ED2 mechanism to unlock funding to deliver improvements to both the Hebridean and Orkney Island groups. The HOWSUM licence condition permits SSEN to submit funding proposals in defined window periods of January 2024 and January 2025 to the Regulator. There are multiple drivers for HOWSUM including future demand and generation forecasts, continued resilience of the island groups, the need to reduce Diesel Embedded Generation (DEG) emissions, and the replacement of life expired assets. HOWSUM proposals are developed through the strategic planning process, consistent with the LRE UM, and relevant SDPs are examined to understand the optimum 2050 visions for connections to these island groups. Detailed planning of whole system options, including transmission, DEG and third party, is considered through detailed analysis. This then feeds into a cost benefit assessment and EJP supported proposals.

4. CONSIDERATION OF OPTIONS AND METHODOLOGY

Standard options on EJPs and overview

For every EJP we have considered the appropriate options taken from our list of standard options. We have used the progressed set of options for each needs case to carry out a comprehensive decision-making process, which includes a consideration of wider whole system and non-network solutions as well as the implication of no network intervention. Often there are cases where these options have combined or split into phases to provide an optimised solution.

Table 5: Standard options for network intervention

Option	Description
Do Nothing	No change to existing network topology
Reinforcement of Existing Assets	Upgrade the existing assets with higher capacities
Reinforcement by Adding New Assets	Install new assets to enhance and complement existing assets to facilitate a greater network capacity
Network Reconfiguration	Facilitating load growth by changing the existing network running arrangement or reallocating the group demands
Flexibility	Procure flexibility alone to facilitate load growth
Flexibility and Reinforcement	Use flexibility procurement to reduce peak demand and defer capital investment on network reinforcement

Developing flexibility options

SSEN's DSO Directorate takes a flexibility first approach ensuring that we have considered flexibility to help meet or defer our future load related system needs.

When considering the potential opportunity for Flexibility Services, we examine three key aspects:

- **Whether flexibility will resolve the technical need.**

  The technical assessment ensures we are only using Flexibility Services where it will safely support the management of the network. In some uses cases this might not be possible, for example: Rutter Pole Replacement schemes; fault level; demand restoration for fault situations. In each of these cases the feasibility of Flexibility Services to resolve the issue was discussed in detail before it was ruled out.
- **The benefits of using Flexibility Services**

  The Common Evaluation Methodology (CEM) tool is used to quantify the benefit of Flexibility Services and determine the number of years Flexibility Services should be used to defer the identified reinforcement for.
- **The ability to procure the required Flexibility Service in the area.**

  This assessment considers whether we can procure Flexibility Services in the region. This includes looking at the portion of domestic and industrial customers, the number of forecasted EVs and any generation or storage facilities expected to be connected. These are combined with forecast flexibility participation rates based on data from all DSOs. This approach has allowed us to focus our market development on areas where we have most confidence, we will achieve the Flexibility Services we need. Without this there would be a risk of getting participation and filling partial volumes, which we would then not use as we would need to accelerate the build solution to ensure the network remained secure.

This forecast of Flexibility Service participation assumes we are successfully growing and developing the market. There are many actions we have taken over the last year to expand the markets. A particular focus has been on our processes this has included moving to Overarching Agreements (with 18 different companies having signed this) and a new Flexibility Market Platform. This has allowed us to attract multiple Flexibility Service aggregators (both suppliers and behind the meter) who are able to offer volume over the widest possible areas and at significant scale. We continue to build the markets further, with planned actions outlined in the Flexibility Roadmap.

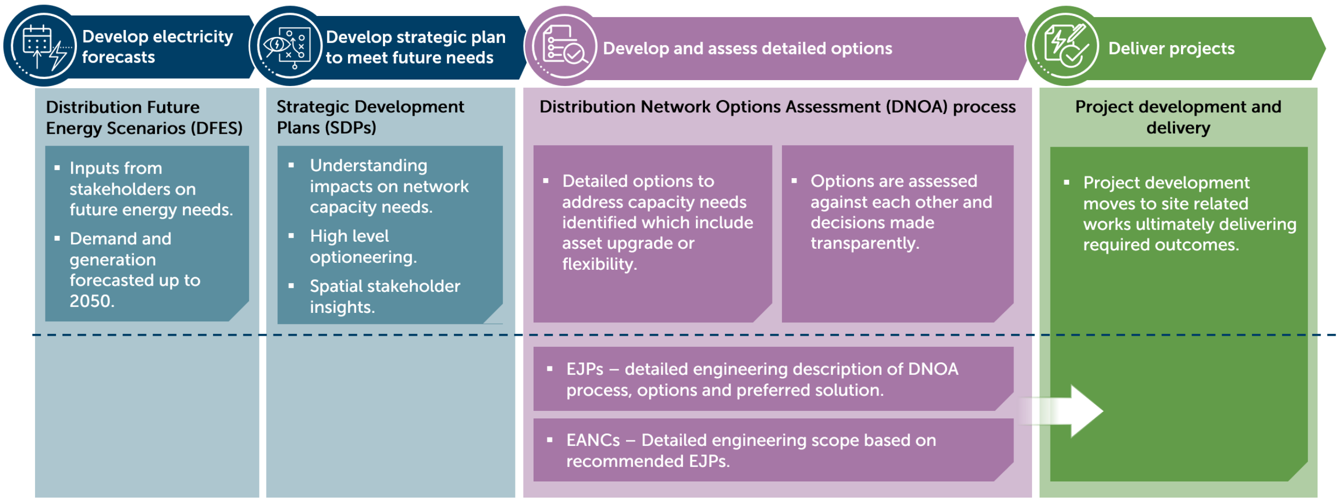
DNOA approach utilised

The DNOA methodology ensures that we compare technical solutions with flexibility options through utilizing the industry standard Common Evaluation Methodology (CEM) CBA tool. The DNOA methodology is consulted on annually with the most recent version published on our website.[14]

Our DNOA decision-making process sits within the overarching Strategic Planning process. We have introduced proportionate measures at the appropriate step to facilitate decision-making, manage conflict resolutions and increase transparency to our stakeholders. A list of the published DNOAs developed from our EJPs are available on our website.[15]

All EJPs included within this submission have been evaluated through the DNOA process.

Figure 8: Options Assessment Process



Assurance

We need to make our decisions transparently such that external stakeholders, including flexibility providers, have confidence that we are a neutral facilitator of markets. We are achieving this through external assurance of our DNOA process. At a high level this process is defined in our DNOA methodology[16] and is reviewed annually.

14 ssen-dnoa-methodology-final-march24.pdf

15 https://www.ssen.co.uk/globalassets/about-us/dso/publication--reports/ssen-dnoa-outcomes-reports-july-2024.pdf

16 ssen-dnoa-methodology-final-march24.pdf

We have employed the technical consultancy, Threepwood to independently assure the process for our DNOA outcomes and underlying EJPs and CBAs in line with this methodology. Threepwood achieve this through two levels of assurance:

A sampling review of published DNOA outcomes to confirm they have been accurately derived from the underlying EJP information in accordance with our internal work instruction. We envisage that the sampling will cover 20% of published outcomes.

A deep dive of three outcomes (or other justified sample size based on organisations sampling method for assurance) of value greater than £4M to cover a flexibility decision, a network investment decision and a flexibility/network investment combined decision in each outcome report. These deeper dives will investigate the underlying EJP information and work development.

The outcomes of these reviews are shared with our DSO Advisory Board for feedback and published on our website for stakeholders. This ensures the DNOAs provide an overall transparent approach to optioneering and decision making. The Powering Customers to Net Zero group also supports this assurance, please refer to Stakeholder Engagement and Whole Systems Opportunities for further information.

5. STAKEHOLDER AND WHOLE ELECTRICITY SYSTEM ENGAGEMENT AND OPPORTUNITIES

DSO enabling efficient Load Related Expenditure

DSO's role is to strategically plan and efficiently provide capacity and faster access to a smart energy network. It also enables services from Distributed Energy Resources to create a net zero world at optimal whole system value for our current and future customers. Our investment in the network is driven by the principles embedded in our DSO Strategy using our toolbox of investing strategically for the future. This includes using flexibility to drive an efficient programme, manage uncertainty and enable earlier connections. For example, this might include a generator that wishes to use an Access SCR curtailed connection managed by our Active Network Management system to maximise generation onto the network at the earliest opportunity. Or a decarbonising industry may choose a time of use connection to fit around industrial processes for a lower connection cost. DSO also supports earlier connection timelines through management of capacity within the GSP T-D interface below agreed limits with the relevant Transmission network. Once connected, we can use DSO flexibility services to manage peak demand until the reinforcement is carried out or whilst the flexibility service is more economically efficient and delivers benefit to consumers.

Policy engagement

Over the last year we have continued to engage with the National Infrastructure Commission (NIC), DESNZ and NESO in the various pieces of policy work they have been undertaking in relation to network planning for a decarbonised future. With NIC we have fed into modelling they have undertaken as part of their study exploring how to ensure local distribution of electricity keeps pace with increasing demand. With DESNZ we have worked closely with the Heat and Infrastructure Team in a pilot project on their modelling of scenarios for decarbonisation of heat. With NESO we continue to provide input into the developments on the benefits that RESPs will provide going forward. While our EJPs have been developed, there has been a distinct shift in the policy from Ofgem from utilisation of flexibility services as a permanent solution to load growth to a position which recognises the need to investment in infrastructure. This aligns with our approach to Flexibility Services being used drive efficient programmes, optimise the timing of investment and support timely delivery of CP 2030 through more effective utilisation of existing assets. We continue to collaborate to pieces of work such as these as they test our assumptions and inform our approach to a decarbonised UK and anticipate the outcomes of each in 2025.

As part of recent engagement with Ofgem in December 2024 and January 2025, Ofgem emphasised that this January 2025 submission must consider the uncertainty of expected policy developments, specifically:

1. the recently published CP2030 Action Plan;
2. NIC Review due in February 2025;
3. RESP methodology decision, due Spring 2025;
4. RIIO-ED3 Framework Decision – Spring 2025;
5. the new connections reform methodology due by Spring 2025;
6. updated NGET power systems analysis expected late 2025 / early 2026; and
7. the tRESP regional pathways output, expected in Q1 2026 at the latest.

We acknowledge the dynamic policy environment and the specific developments Ofgem referenced. In practice we expect these to have limited bearing on the necessity of commencing new and enhanced schemes within ED2 that will, regardless of these factors, be critical to meet Net Zero, optimise the energy system, and deliver economic growth. Accelerating efficient Net Zero delivery and unlocking growth are core drivers for these changes in the wider policy landscape, further underpinning the necessity of our LRE programme and the assurances required so that we can proceed and deliver it. It is imperative that Ofgem is cognisant of the very real supply chain and lead time constraints we are facing and the materiality of financial commitment we are proposing to make.

Below we have addressed each of the recent or expected policy developments directly.

The recently published CP2030 Action Plan
We are on a critical delivery path which includes gaining confidence through this LRE UM that we can send a signal to the supply chain to ramp up skills and manufacturing capacity. Delays to this will further impact CP2030 given we have already adopted a modular strategic approach, where the impact of CP2030 can be mitigated within the committed programmes, mainly through timing changes. While we appreciate that it is appropriate for connections reforms and connections reordering to impact investments, our strategic approach means we are building for 2050, mitigating the impact that reordering of connections will have to our strategy.

NIC Review due in February 2025
We have contributed to the NIC review and have been engaging proactively with the NIC throughout the process. We have a good understanding on the current direction of travel and are confident that our overarching load strategy is in alignment, with its focus on proactive investment in the context of a long-term 2050 vision.

The NIC terms of references are clear that: "*the Commission will not provide an assessment on the overall level of investment required to upgrade the distribution network to meet the requirements of net zero*", and "*will not re-open RIIO-ED2*".[17] The terms of reference highlight that the review will be providing recommendations on whether the regulatory model is for purpose for net zero. As such, we do not see that the findings of the NIC review would have any direct impact on the investments proposed in our RIIO-ED2 re-opener submission.

RESP methodology decision, due Spring 2025
We have been engaging proactively in the development of the RESP framework, including responding to the policy framework consultation published in July. The consultation consults on the key building blocks for the RESP, regional governance and regional boundaries.[18]

We expect the policy framework decision in the Spring to set out Ofgem's decision and next steps on building blocks, RESP, regional governance and regional boundaries. As such we do not think that any of these decisions will have any direct impact on the investments proposed in our RIIO-ED2 submission.

RIIO-ED3 Framework Decision – Spring 2025
We have recently submitted our response to the RIIO-ED3 Framework Consultation. As this is a separate framework to RIIO-ED2, it would not be appropriate for the Framework Decision to impact the operation of a RIIO-ED2 re-opener mechanism, which was designed and implemented into the licence in the context of the RIIO-ED2 framework. At Final Determinations for RIIO-ED2, Ofgem chose to rebaseline our plan in line with ST DFES scenario, the least ambitious net-zero compliant, noting the following: "*We have reduced LRE allowances from those proposed in our Draft Determinations by £188m to reflect consultation feedback on our cost assessment methodology. This ex-ante allowance is calibrated using various parameters, including adjustments of some elements to match a net zero compliant Future Energy Scenario (FES), System Transformation, for LCT uptake. However, we have implemented a package of UMs that will enable networks to invest immediately and without administrative burden if LCT uptake exceeds this scenario.*"[19]

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17 Terms of reference – distribution networks study - GOV.UK, 27 February 2024

18 Regional Energy Strategic Plan policy framework consultation, Ofgem, 30 July 2024

19 RIIO-ED2 Final Determinations Core Methodology Document, Ofgem, 30 November 2022

Our response to the RIIO-ED3 consultation includes our view on the transitional RESP (tRESP) for RIIO-ED3. We are proposing an incremental approach to developing tRESP, building on existing DNO activities and collaborating with the NESO to ensure a timely tRESP output, ahead of January 2026. tRESP is a new concept, introduced in the context of RIIO-ED3.

We do not think it would be reasonable to wait for tRESP output to proceed with investment decisions within RIIO-ED2. We currently have limited certainty on the exact nature of RESP, its scope and timings. Ultimately, waiting for tRESP outputs in January 2026 before activating a RIIO-ED2 load re-opener would put delivery of net zero at risk and increase costs for customers.

We need to be able to make investment decisions now so that delivery within ED2 and at the start of ED3 is physically possible. The change in capacity requirements on the network is from a combination of Access SCR (Significant Code Review) driven connection schemes; ED2 network compliance schemes (as forecast under the CT DFES scenario); and larger schemes which we need to start in ED2 in order to complete them in ED3. Delivery of these schemes is critical to ensure we are on track to meet Net Zero and CP2030 and forms part of our plan to enable an optimised energy system.

New connections reform methodology due by Spring 2025
We are fully engaged in the consultations that make up the Connections reform. While we recognise that the new methodology to be introduced by Spring 2025 will impact the way customers request and gain access to the network, we do not believe it should have any bearing on our request for additional allowance through the LRE mechanism. Connections reform will change the ordering of connections but not the capacity needed to deliver Net Zero targets. Therefore, in order to achieve this, we need to continue with our strategic plans to deliver for our customers as set out in our submission.

Updated NGET power systems analysis expected late 2025 / early 2026
While NGET's power systems analysis will continue to inform our interactions in SEPD with the Transmission Operator (TO) it would be entirely inappropriate for the investment and load growth required within RIIO-ED2 to be delayed because of NGET's future (RIIO-T3) analysis. The design of our Net Zero First investment approach means that we are taking a proactive approach sizing to 2050, building modular whole system solutions rather than incremental solutions reacting to individual connection requests. This means that we are applying an efficient, low regret solution for the customers and communities that we serve, looking at the wider picture, whilst being ready to flex to specific changes such as those which the updated NGET power systems analysis might highlight.

The tRESP regional pathways output, expected in Q1 2026 at the latest.
Please refer to the points made above noted in relation to the RIIO-ED3 Framework Decision in Spring 2025.

We will continue to engage with Ofgem, Government, NESO, NIC and others on relevant policy, to ensure that our approach remains fit for the future. We remain confident that our network investment strategy enables sufficient flexibility to deliver the right investment at the right time within the changing policy environment within which we currently sit.

Strategic Development Plan engagement

Strategic Development Plans
The UK is decarbonizing predominately through electrification, with investment required across every GSP to enable Net Zero by 2050. As electricity is the dominant energy vector to enable the transition, our approach needs to encompass every GSP in our licence areas. We are engaging with industry, generators and LAs to produce SDPs for each GSP. This has enabled us to ensure there is a blueprint, that is cross vector and LA agreed – a spatial plan of investment options to get industry decarbonized, domestic heating and transport away from fossil fuels, and enable renewable generators to connect below the GSP behind T/D limits. This

gives these plans a democratic mandate, and cross vector, coordinated technical mandate and is aligning with the direction of the tRESP function in the future. Our SDPs build on the principle of the critical importance of bottom-up input to long term strategic planning – they utilise energy scenarios (DFES), forthcoming pipeline information and stakeholder insights from local plans, to formulate informed forecasts of the known Distribution network requirements to deliver on 2030 and ensure this fits with pathways to deliver local networks to meet GB 2050 net zero ambitions.

The insights from DFES inform our SDPs which then recommend constraints to be addressed in a timely manner through Engineering Justification Papers that then go through the Distribution Network Options Analysis review.

We have committed to engage on all SDPs as we produce them over a 12-month period. The current forecast plan is shown in Figure 9.

Figure 9: Priority Order of SDP Development

Already published	Q1 2025	Q2 2025	Q3 2025
• Ealing (SEPD) • Fawley (SEPD) • Port Ann (Islay & Jura, Colonsay) (SHEPD) • Taynuilt (Mull, Coll, Tiree) (SHEPD) • Thurso South (SHEPD) • Cowley (SEPD) • North Hyde (SEPD)	• Shetland (SHEPD) • Kintore (SHEPD) • Persley(SHEPD) • Fleet (SEPD) • Beauly (SHEPD) • Lovedean (SEPD) • Iver 66kV (SEPD) • Skye & Western Isles (SHEPD) • Iver 132kV (SEPD) • Fort Augustus (SHEPD)	• Keith (SHEPD) • Errochty (SHEPD) • Mannington (SEPD) • Melksham (SEPD) • Mybster (SHEPD) • Botley Wood (SEPD) • Laleham (SEPD) • Willesden (SEPD) • Tealing (SHEPD) • Bramley (Basingstoke) (SEPD) • Nursling (SEPD)	• Braco (SHEPD) • East Claydon (SEPD) • Axminster (SEPD) • Chickerell (SEPD) • Inveraman (SHEPD) • Amersham (SEPD) • Dounreay (SHEPD) • Peterhead (SHEPD) • Inverness (SHEPD) • Minety (SEPD) • Bramley (Thatcham) (SEPD)

For each SDP, we share a draft version for consultation; this is an opportunity for our stakeholders and customers to offer feedback and insight, which we then look to incorporate for final publication. Alongside the consultation we offer opportunities for bilateral meetings and workshops to talk through our plans in more detail and hear views from local interested stakeholders.

Over Summer 2024 we engaged on the Ealing SDP – during which we posed questions to our stakeholders including:

- Have we missed any significant sites or developments that use or generate electricity specific to the local area covered by Ealing GSP?
- Have we correctly identified and represented the net zero ambitions of your local area?
- Do you have any feedback for us on how we are presenting this information to you? For example, do you have any suggestions on how we could make it more accessible.
- Is there any further information you would like to see in this Strategic Development Plan or future Strategic Development Plans?
- Do you have any feedback on how we have consulted with you?
- Is there anything else you'd like to add?

Following the consultation for this SDP, several changes have been made to the updated document to reflect the feedback received from our stakeholders. A summary of these changes is tabulated below:

Table 6: Summary of Stakeholder Feedback on Ealing SDP

Feedback theme	Action taken
Flexibility within relevant supply area.	Added further text to clarify estimations
Local Area Energy Planning	Added additional reference to these plans and ongoing workstreams to better reflect these plans in future iterations.
Solar PV of council owned buildings	Breakdown of specific building blocks informing solar PV forecasts. Reference to council ambitions in this area.
Heat networks for decarbonisation of heat	Highlight awareness of the plans for heat networks in the area.
Local Authority EV charging strategies	Referenced specific strategy and targets from this strategy.
Data centres	Further described our approach to handling these projected demands and highlighted requirement for improvement.
Local net zero ambition	Referenced Climate Action Plan to demonstrate ambition.

LENZA & LAEP

To help our stakeholders develop LAEPs (Local Area Energy Plans) we have brought the network to life through our LENZA (Local Energy Net Zero Accelerator) tool.

For the past three years we've been working in close partnership with the LAs across our licence areas, to support them in producing LEAPs to help articulate their net zero ambitions ahead of plans for delivery. We've done this in a range of ways; through practical support provided by our team of dedicated Net Zero Advisors (who are allocated by RESP areas), and through our LENZA tool, a geospatial planning platform powered by Advanced Infrastructure Technology Limited's (AITL) LAEP+ software.

LENZA is designed to support users in their strategic energy planning endeavours, including the creation of Local Area Energy Plans (LAEPs) and, where relevant, Local Heat and Energy Efficiency Strategies (LHEES). The platform provides LAs and their delivery partners with data and modelling tools that support informed decision making, including information on network capacity, building stock, and energy consumption.

The tool empowers users to plan decarbonisation pathways, which in turn drive SSEN Distribution's longer-term strategic network planning that will power local net zero ambition.

Whole electricity system engagement

We have met regularly with the Transmission networks for our licence areas – NGET and SHET, as well as NESO. This has included regular Joint System Design Liaison (JSDL) meetings which allow us to discuss developments impacting each other across the T-D boundary. We have enhanced this engagement through:

- Bilateral and regionally focused meetings with NGET on their future RIIO-T3 proposals to ensure overall alignment and sharing of insights.
- Bilateral meetings with NESO to discuss our approach to strategic planning and gain their input into both the SDP form and process.

- Regular meetings with SHET to ensure a co-ordinated approach to network development in the North of Scotland.

These meetings and other discussions have enabled us to not just our load related expenditure plan but also opportunities to utilise flexible resource to get parties connected more quickly. This includes:

- Development of an agreed ramping process for demand in West London
- Implementation of T-D limits across both our licence areas
- Installation of a high-speed data link between control centres.

DSO transparency of decisions

Our governance arrangements embody our Smart, Fair, Now approach, ensuring transparent, unbiased actions to efficiently accelerate towards net zero. We believe that close working between DSO, Asset, Connections and Delivery teams is critical to achieving net zero efficiently. Under our governance model, the DSO is functionally separate to our Asset, Customer and Delivery functions but remains part of the same organisation. There are clear accountabilities for load (DSO) and non-load (Asset) decision making. We mitigate any potential conflicts of interest through additional assurance and independent oversight of our DSO function. Our integrated DSO business model enables us to operate efficiently by sharing data between functions and to deliver our connections pipeline and LCT uptake more quickly. We recognise the need to make our decision-making processes transparent to stakeholders. As such, we have published and consulted on our methodologies for avoiding conflict of interest and providing transparency in our decision making both in network planning (DNOA) and operations (Operational Decision Making (ODM).[20]

Our DSO governance model includes functional separation of DSO into a separate directorate accountable for all load (capacity) decision making across flexibility, access and network investment options using the DNOA process. This is in the opportunity and development stages of our Distribution Governance Investment Framework (DGIF) gated process shown below.

Figure 10: SSEN Distribution Governance Investment Framework

DSO carries out the Opportunity Assessment and Network Options Assessment for all load (capacity) related expenditure and then hands over an Electrical Asset Needs Case at Gate 2 to the Asset Directorate. This enables coordination for efficient delivery with the wider asset (non-load) programme prior to refinement and execution by our delivery team. Any conflict between asset health driven work or connection timelines are addressed through coordination meetings in the Opportunity Assessment stage. If these have not been adequately addressed before Gate 2, any conflict is resolved via the DSO and Asset functions, representing the load and non-load network needs respectively. Assurance is carried out by a third party on DSO investment decisions following the DNOA process. The Independent DSO Advisory Board reviews the Assurance report and constructively challenges the methodology from a customer and social benefit perspective. Load related work issued for refinement through Gate 2 for delivery in ED2 and beyond, as contained within this submission, is managed via this process and governance outlined above.

20 ssen-dnoa-methodology-final-march24.pdf, SSEN Operational Decision Making ODM

Stakeholder feedback is baked into the design and review of key processes such as DNOA, ODM and Flex Roadmap and is actively assisted through data and insights such as LENZA and our real-time operational data. Insight is gathered through formal consultations, bilateral conversation and day to day interactions and used to refine and update our activities.

6. COST AND REGULATORY INFORMATION

Summary of approach

The rate of growth of connections in the SEPD area including data centres, and rapid decarbonisation of key industries, predominately in SHEPD has led to a step change in capacity requirements on the network compared to what was envisaged in 2019, when the underlying forecast data on which the ED2 Business Plan, was produced. Our agreement to the settlement of the ED2 price control was on the understanding that Ofgem had built into the price control mechanisms that would deal with the uncertainty that presented itself in a rapidly decarbonising environment. During this time Ofgem's own governance has been adjusted to include the 'Net Zero Duty' and the 'Growth Duty'.

To this end, we are submitting what we have identified as the necessary increase in investment to ensure that we are on track to meet Net Zero and enable economic growth across the areas represented by our DNO licence areas. Our approach to costs included reviewing the existing allowances for Load Related Expenditure, LRE (baseline), the interaction with the LRE Volume Drivers, and any other categories that have been allowed as LRE (for example Green Recovery, and Flexibility Expenditure). The LRE allowances package encompasses the RRP categories of CV1 – Primary Reinforcement, CV2 – Secondary Reinforcement, CV3 – Fault Level Reinforcement, CV4 – New Transmission Capacity Charges and C2 – Connections (Cost Apportioned CAPEX), which we will be referencing throughout this section of the report. The ED2 allowance is based on modelled costs in 20/21 prices, which is the price base that we will use throughout the report. Since 20/21 there has been unprecedented increases due to inflation (c30%), along with supply chain issues which mean that the costs that our contract partners and procurement pipelines are seeing are not reflective of the rates for ED2.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] e need Ofgem to allow reasonably incurred expenditure in developing the load schemes, including necessary committed expenditure, and to treat this expenditure separately in RIIO-ED3 benchmarking. This is necessary to avoid penalising us for the necessary spend incurred for critical load schemes. We need Ofgem to agree that this work is required and agree commitment from Ofgem to assess Part 2 of our submission in the next additional LRE UM re-opener window that Ofgem will direct, in accordance with Ofgem's assessment of Part 1 of our submission from January 2025 for the recovery of these costs.

This re-opener submission encompasses work on the 132kV and EHV network, with the work on the HV and LV networks being accounted for through the Volume Adjustment Mechanisms.

[redacted]

[redacted]

Allowance adjustment

The ED2 Load Related allowances package can be summarised by the following table and is split across various CVR RRP C and CV tables as shown.

Table 7: Baseline LRE ex ante non variant allowance excluding Volume Drivers (£m, 20/21)

Table RRP Ref	Table Name	Load Related Allowances after NPCA and Ongoing Efficiency	
		SEPD	SHEPD
C2	Connections within the price control	152.2	55.2
CV1	Reinforcement (Primary Network)	106.0	34.6
CV2	Reinforcement (Secondary Network)	3.1	2.1
CV3	Fault Level Reinforcement	36.9	2.1
CV4	New Transmission Capacity Charges	1.4	19.5
CV25	High Value Projects	46.2*	-
Total LRE Allowances		**345.8**	**113.6**

*Allowance relates to Fleet-Bramley Project. Spend for Fleet-Bramley will be reported in CV1 – Reinforcement (Primary Network).

As much of CV2 is made up of the Secondary Reinforcement Volume Driver (SRVD) and Low Voltage Services Volume Driver (LVSVD) the trigger thresholds for SHEPD and SEPD are £113.69m and £345.77m respectively. The materiality thresholds are as below, and we expect to exceed these with the extra investment on LRE.

Table 8: RIIO-ED2 Re-opener Materiality Thresholds (£m, 20/21)

	SEPD	SHEPD
RIIO-ED2 Materiality Thresholds	5.56	2.16

We have also included an element for the Indirect Scaler Volume Driver which applies a mechanistic upwards cost adjustment of 10.8% to any justified spend related to the LRE Re-opener, SRVD and LVSVD. In this paper we have included the uplift related to the LRE Re-opener only.

The table below summarises our current view of forecast costs for non-variant load related allowances (i.e. baseline allowances) and the additional allowances we expect will be needed to deliver our load programme under the LRE Re-opener. Please note that these are subject to change as we finalise the costs of projects and may be subject to operational constraints.

[redacted]

[redacted]

The projects that make up these totals are a combination of schemes that have been reworked from our ED2 business plan submission, where the MVA released was SEPD 1039 MVA and SHEPD 202 MVA. A list of these projects and how they relate to the LRE UM submitted projects can be found in Appendix 4.

21 NTCC costs are not charged until after work has taken place. This reduction is a consequence of transmission delivery timescales being longer than anticipated and consequentially pushing these costs out, though the work remains committed.

The comparison between MVA released committed to in our ED2 settlement to our forecast MVA to be released within ED2 based on the completion of the work outlined in this submission, is displayed in Table 2 in the Executive Summary.

[redacted]

As mentioned in our *Strategic Needs Case* section, there are three broad categories of projects that we are looking to submit a needs case for, which cut across these categories of investment:

- **ED2 network compliance schemes**. These are forecast under CT scenario, with DFES load growth layered onto the existing demand and contracted demand. There risks being network compliance issues within ED2 if the associated work is not undertaken.
- **Schemes which need to start in ED2 to complete in ED3**. These schemes have long lead times for larger works which we can see are needed in ED3. If not undertaken in ED2, for these projects there would be network compliance issues in ED3 and/or delays to connection in ED3.
- **Access SCR schemes**. These are connection applications that trigger costs within the price control. Implications of not undertaking this work now is that customers would be waiting until ED3 for connection.

Table 12: LRE Cost by Investment Categories

[redacted]

Treatment of costs

Within this submission we have included in the overall totals the projects that make up the [redacted] CV1 Primary and CV3 Fault Level Reinforcement, detailing all priority EJPs where 132kV and EHV reinforcement is the main driver. The full list of these EJPs can be found in Appendix 4, where they are split into ranges of costs <£2m and £2-£5m. All prices are in 20/21 price base and represent the allowed ED2 unit cost. [redacted]

22 This is based on the schemes with forecast completion dates within ED2, and not including the additional MVA that will be released for those schemes that will complete within ED3.

[redacted] The Deliverability and Risk Section of this report describes the increase in costs that we are seeing after recent returns from our contractors. We have outlined the impact on our network from growth in connections in Table 4. We have detailed how our LRE Re-opener submission is split across Load Related Expenditure Categories in the Tables 9, 10 and 12 above.

[redacted]

[redacted]

[redacted]

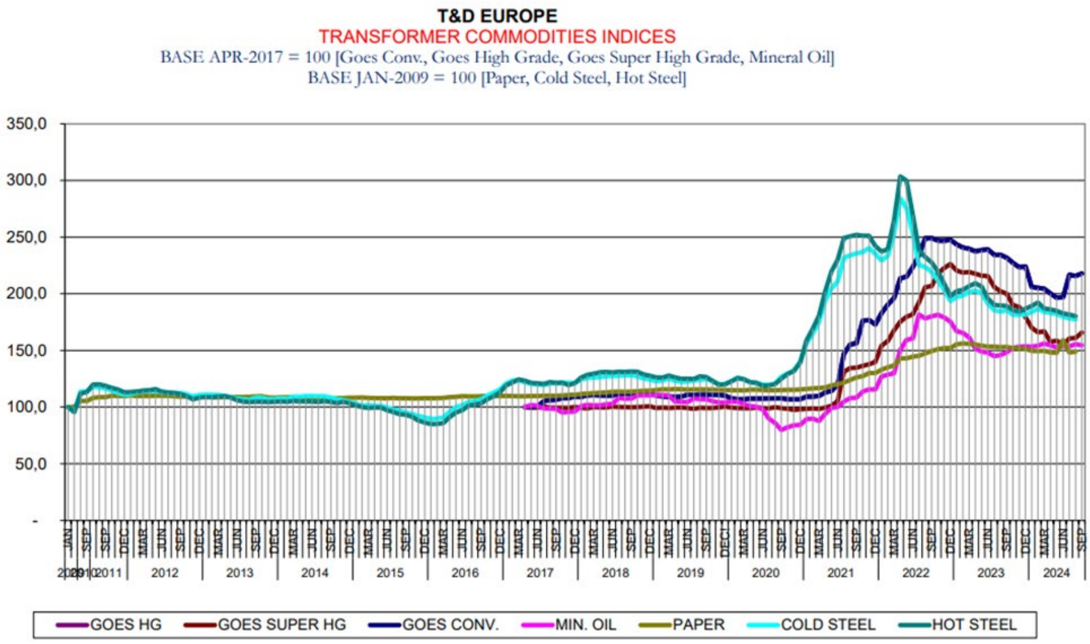
Driving efficiency of delivery

'MVA released' has been used as a simple measure of efficiency for Load Related Expenditure (LRE). Some schemes in the LRE portfolio are required to manage voltage and fault level compliance too. To drive efficiency of delivery we are managing schemes as portfolios of work by grid supply point, so work is co-ordinated and assigned to framework contractors who competitively tendered for the work.

In the submission of costs that we will make in the next additional LRE UM re-opener window that Ofgem will direct, through a range of metrics we will demonstrate efficiency in delivery and will remain cognisant of the ongoing challenges in the supply chain and cost volatility of core components. Since 2019, there has been a step change in the cost of goods and services in relation to all industries, but specifically the components of electrification as the key decarbonising energy vector. Our ED2 settlement specified allowed unit costs, which are now far below the cost at which the reinforcement projects specified in our EJPs can be delivered.

As can be seen from Figure 13 after a relatively steady cost base of the components of Transformer production for almost 10 years, there has since been an almost doubling of the costs of the constituents of transformer manufacture. These reached a peak in early 2022 and have now started to converge and settle about 100 points up on the index for 20/21 when the ED2 prices were set. [redacted]

Figure 13: Transformer Commodities Indices



source: tdeurope.eu (Oct 2024)

[redacted]

NARMS (Network Asset Risk Matrix)

As part of the ongoing and strategic LRE investment programs, we are and will continue to monitor and review our portfolio of works to manage the Network Asset Risk Metric (NARM) impacts across both license areas, to understand the immediate and long-term effects on the network and our investment programs. These assessments have been carried out across our current ED2 investment programs. Any synergies and efficiencies between projects have been aligned to reduce the impact on our customers and the network, while driving efficient delivery and value. These ongoing assessments will continue and form part of our ED3 impact assessments and submission for future NARM investment programs.

7. JUSTIFICATION OF OPTIONEERING

The modular approach that we are taking to load related investment allows us to synergise the variety of pressures on the network that require investment between now and 2050. All investment set out in this Strategic Needs Case submission is driven by constraints forecast within ED2, or where we need to start work in ED2 to avoid constraints in ED3. We considered the 2050 network design and ensure we are future proofing. This could be sizing assets to meet 2050 for low marginal cost or taking a staged approach to 2050. This is based on a low regret planning approach, as tested through our CBAs (Cost Benefit Analyses). This is aligned with the policy decisions that have recently been made, including CP2030, and with the indications of decisions that will be made in 2025. These decisions will remain applicable and provide a strong justification for progressing with our investment approach, so we are concerned that Ofgem is asking us to take even more risk as we accelerate the pace of load delivery required.

To ensure we are delivering efficiently for the customers of today and tomorrow, we consider our proactive approach to sizing to 2050 is vital, building modular whole system solutions rather than incremental solutions reacting to individual connection requests.

Below we have outlined and summarised the tools that we have applied to establish the appropriate solution for each of the capacity constraints identified.

Standard options on EJPs and overview

In *Section 4 Consideration of Options and Methodology* we have outlined the standard options that we use to carry out a comprehensive decision-making process, to ultimately provide an optimised solution. This includes a consideration of wider whole system and non-network solutions as well as the implication of no network intervention.

Please refer back to Section 4 for further details about the use of standard options in EJPs.

Strategic CBA

We have outlined in *Section 2 Business Strategy Alignment* how we have developed and used our Strategic CBA to enhance the existing CBA and CEM tools. Use of our Strategic CBA in this way has allowed us to take least worst regrets approach to investing strategically and consider broader benefits. This can help identification of the optimum timing of an intervention by considering requirements under multiple DFES scenarios. It can also consider the size and scope of solution required, i.e. whether there is benefit on a broader more strategic solution implementation rather than an incremental approach.

Please refer back to Section 2 for further details about our Strategic CBA.

Ofgem CBA

We utilise Ofgem's framework to justify a wide range of potential interventions. This standardised approach supports the Regulator to understand our proposals through provision of other alternatives and key information. The purpose of the CBA is to enable us to demonstrate that our proposals are optimal solutions and best value for consumers.

We measure this against the status quo position in the absence of any intervention, unless this is not a credible option. In these cases, we will choose a lowest investment option as the technically feasible baseline.

Costs and benefits are then considered over and above the baseline scenario with costs classified as negative and benefits as positive impacts. We consider societal benefits (i.e. avoided costs) for each option.

All our EJPs employ the Ofgem CBA to ensure the most cost-effective option is recommended.

CEM Tool

The CEM (Common Evaluation Methodology) tool supports the use of Flexibility to defer network reinforcement. As in line with Ofgem's RIIO-ED2 methodology, SSEN committed to a flexibility first approach, meaning that flexibility services are considered as an option for the resolution of every identified network constraint. The CEM tool provides the backbone of the process for determining the optimal solution between traditional network reinforcement, procurement of flexibility services, and a combination of the two.

The CEM tool is a standardised cost benefit assessment tool issued by the Open Networks program and used by all DNOs in the UK. It performs discounted cash flow analysis to compare the costs and benefits of a traditional network reinforcement solution against the use of a flexibility service to manage a constraint. The CEM tool can recommend an immediate reinforcement, the use of flexibility long-term, or the deferral of a reinforcement using flexibility. The economic benefits of flexibility are evaluated through this tool as being deferred investment of reinforcement, however there is much wider value to the GB Energy system of facilitating flexibility at the local level, which Flexibility Services at Distribution level are starting to unlock. We have used the CEM tool when developing our EJPs as part of our Net Zero First approach. This helps ensure that we are investing in our infrastructure of the network in the right place at the right time.

8. DELIVERABILITY AND RISK

To address the scale and complexity of the LRE programme and all other drivers for ED2, we have secured three dedicated delivery partners for our SEPD region, each aligned with a distinct delivery group. This structure strengthens our capacity to manage timelines and resource demands effectively. In collaboration with our contractors, we have developed a delivery schedule that provides clear visibility across the portfolio, allowing for coordinated planning and proactive resource allocation. SHEPD are securing dedicated delivery partners utilising three routes to market providing control over the priority of projects and expected delivery.

[redacted]

Each contractor has developed a resource profile based on their expected project requirements. SEPD has consolidated these into an integrated view across the entire programme, allowing us to identify potential pinch points and proactively manage resource risks. This approach not only enhances our capacity to address immediate resource needs but also supports efforts to expand the availability of critical skills across the industry.

This deliverability and risk section outlines our structured approach to project execution, highlighting our readiness to meet Ofgem's requirements for transparency and accountability. Within this section, we cover:

- A detailed delivery programme.
- A clear assessment of our access to critical resources, including mitigation strategies for potential constraints.
- Robust risk management and mitigation strategies, with contingency plans to address deviations.
- Reporting mechanisms through our DGIF, supporting structured monitoring, timely risk management, and transparent communication with stakeholders.

We reaffirm our commitment to continuous improvement throughout ED2. By embedding flexibility and structured oversight, we aim to refine our approach to deliverability, optimising our capacity to adapt to evolving programme demands and regulatory priorities, ensuring reliable outcomes for stakeholders and sustained value for customers.

The following sections provide a detailed account of our deliverability and risk strategy, covering our project timelines, resource allocation, risk mitigation measures, and reporting mechanisms – all components of our proactive approach to resilient programme delivery.

SEPD & SHEPD Setting up for Success

The ED2 period marks a transformation in how Distribution will deliver for our customers and on our net zero ambitions, providing the delivery platform for future growth as Load investment increases. [redacted] In SEPD, we have completed a competitive procurement process, securing three dedicated delivery partners aligned to each delivery group: OCU for Delivery Group A (DGA), Clancy for Delivery Group B (DGB), and Keltbray for Delivery Group C (DGC). These partnerships enable SEPD to transition from transactional supplier relationships to collaborative partnerships that streamline planning, increase visibility, and ensure resource alignment across the programme. This structure positions SEPD to efficiently meet LRE milestones and reinforces Ofgem's standards for timely and consistent delivery.

SHEPD completed a full review of the work required in ED2 and prioritised projects within LRE. SHEPD is also progressing through its own tender process and will incorporate lessons learned from SEPD to optimise its transition to the delivery partner model. With contracts awarded in January 2025, SHEPD will leverage these tested strategies and tailor them to the specific challenges and requirements of its operating region. This staggered approach ensures that SHEPD benefits from proven methods while meeting RIIO-ED2 objectives effectively.

This section provides an overview of SSEN's dual-region delivery strategy, laying the groundwork for the following sections, which will address specific strategies, milestones, and expected outcomes across SEPD and SHEPD.

Delivery Programme

The delivery programme is organised across multiple financial year targets, ensuring timely completion of priority projects to meet network demand, regulatory requirements and connect customers. Key milestones include obtaining critical mod application approvals, enabling dependent projects to advance without disruption. Projects are prioritised to ensure that these capacity upgrades are delivered on schedule, fulfilling both customer and system requirements.

[redacted]

[redacted]

Outages are a key consideration in ensuring the accuracy of our LRE delivery schedule, and SSEN has established a robust structure to manage this effectively. We have leveraged insights from our contractors, combined with data from previous outages on similar projects, to evaluate and confirm the feasibility of planned outage windows. This approach has enabled us to integrate realistic outage schedules into the overall programme, ensuring that project timelines are deliverable.

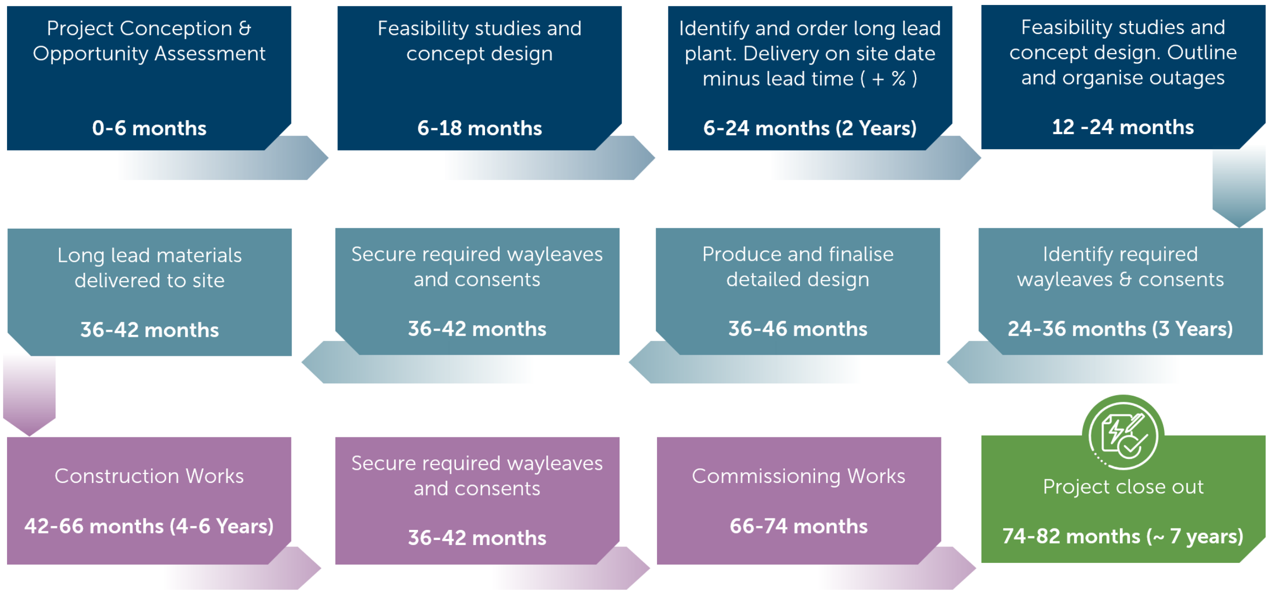
Through this proactive planning, we have established a solid foundation that strengthens confidence in our delivery timelines. Our focus on early stakeholder engagement allows us to identify and address outage requirements in advance, particularly for projects involving complex or extended outages. This early engagement with key stakeholders ensures that necessary approvals are secured promptly, reducing the risk of disruptions to the schedule.

Looking forward, SSEN is committed to a structured, long-term outage management process that enhances both planning accuracy and delivery efficiency. This includes the timely production of Single Line Diagrams (SLDs) to support detailed outage planning and the logging of outage requirements in our access booking tool, providing a centralised and accessible record of planned outages.

In summary, our phased and structured approach to the SEPD work aligns project schedules with critical milestones, resource availability, and well-planned outage windows. The following sections will provide further detail on our resource strategies, risk management practices, and monitoring frameworks, supporting the successful and reliable delivery of our commitments across the SEPD region.

Below is a project lifecycle illustrating typical durations. This highlights the importance of early confirmation of future funding to ensure that customers can be connected to the network, when they need additional capacity, so as not to delay economic growth, and intervention decisions being required in advance of network non-compliance or the need for curtailment. It is essential that preparatory activities are initiated and completed in advance, enabling the long-term project to progress smoothly and meet its completion timeline.

Figure 17: Project Lifecycle



Resources

SSEN's resource strategy is structured into two key areas: Critical Contractor Resources and Plant Resourcing. This approach allows us to address both workforce needs and the procurement of essential plant items, mitigating risks associated with resource shortages and supporting seamless project progression. Without this additional funding for our LRE work we will not be able to commit to our contractors or our suppliers, this will heavily impact our ability to deliver the ED2 programme and subsequently the ED3 programme. With funding in place this will ensure continuity and reduce risk of delays. Below, we outline our strategies for each area, demonstrating SSEN's comprehensive commitment to resource stability and alignment with Ofgem's expectations.

Critical Contractor Resources
In conjunction with our delivery partners, SSEN has implemented a comprehensive resource strategy to ensure sufficient capacity is available at every stage of the ED2. Through a detailed resource smoothing approach, we have aligned the LRE programme schedule with available resources, carefully balancing peak demands across all phases.

SSEN has collaborated closely with each of our SEPD delivery partners – OCU, Keltbray, and Clancy – to develop an accurate, consolidated resource profile that encompasses all essential roles, skills, and materials needed across SEPD's Load Related Expenditure (LRE) projects. Through this collaborative process, we have identified certain critical resources – such as Senior Authorised Persons (SAP), commissioning engineers, and other specialist roles – that are in high demand but limited supply. These critical resources have been mapped in depth across SEPD projects, providing visibility into potential competing demands and allowing contractors to proactively manage their programme.

Each SEPD contractor has been required to use these insights to perform their own resource smoothing exercises, aligning their schedules to ensure that the right resources are available at the necessary stages of each project. By supporting our delivery partners with this comprehensive resource mapping, SSEN has enabled them to optimise resource availability, minimising the risk of overlaps and shortages during peak demand periods. This collaborative approach underpins SEPD's delivery timelines, ensuring contractors are well-prepared to meet both current and projected demands across the programme.

For SHEPD, we are following a similar strategy to support resource planning, tailored to the specific needs of its projects, and ensuring efficient contractor collaboration. The new Large Capital Delivery contractor framework was awarded in January 2025.

These strategies provide a resilient foundation for resource readiness, aligning with SEPD's delivery objectives and Ofgem's expectations for reliable programme execution. By supporting delivery partners in their own resource management and risk mitigation, SSEN ensures that each phase of the programme can proceed smoothly, even during peak demand.

Long Lead Plant & Materials
Historically, SSEN operated in a more predictable supply chain environment, with lower internal demand for long lead plant items and greater manufacturing capacity. This allowed for a responsive, ad hoc procurement approach that effectively met project delivery timelines. However, global shifts in supply and demand dynamics, combined with SSEN's evolving network requirements – particularly the unprecedented demand for 132kV GIS equipment – have fundamentally changed this landscape. Supply chains are now more constrained, requiring a proactive and structured approach to ensure deliverability.

[redacted] This maintains delivery confidence while minimising unnecessary costs.

Our approach is underpinned by project schedules with supplier lead times. [redacted] This alignment ensures that the delivery of long lead items supports overall programme timelines and project progression.

SSEN's procurement timelines are designed to meet project schedules while accounting for supply chain lead times. This approach reflects our commitment to ensuring that long lead plant items are effectively managed as a core part of our deliverability strategy. [redacted]

SSEN's strategy also considers the broader market context. [redacted]

[redacted]

In addition, the increasing competition between Transmission (T) and Distribution (D) networks for key resources, such as 132kV GIS equipment, presents an industry-wide challenge. From Ofgem's RIIO-ED3 Framework consultation we understand that Ofgem is still building its understanding of Distribution challenges against those of Transmission, where the focus has been on long lead times. Advanced procurement mechanisms in Transmission could place further strain on supply chains that we share, potentially extending lead times and impacting SSEN Distribution's ability to deliver.

[redacted]

Delivery Mitigation Measures

Below, we outline SSEN's mitigation measures across key risk areas, designed to address Ofgem's expectation for a robust response to potential project delivery deviations.

SSEN's mitigation strategies are underpinned by a layered approach to risk management, which includes both immediate responses to identified risks and long-term contingency plans. Key mitigation themes include:

- **Contingency Resources**: SSEN has established backup resource pools and alternative sourcing for critical roles, allowing for rapid deployment in cases of unexpected resource shortages.
- **Outage Management**: By structuring the LRE programme with built-in flexibility, SSEN can adjust project schedules dynamically, prioritising critical milestones while minimising disruption.
- [redacted]

These strategies enable SSEN to respond effectively to potential issues, ensuring that the programme's key milestones remain on track and delivery risks are minimised.

Consenting & Wayleaves

Securing land consents and wayleaves is essential to the LRE programme's progression. SSEN has developed a structured approach to obtaining these consents, with early engagement as a core element. By working with landowners, LAs, and stakeholders at the onset of projects, we streamline approval processes and secure permissions in a timely manner. [redacted]

There is an internal programme throughout Distribution which is aiming to improve our current processes for all areas of Distribution but specifically aims to deliver efficiencies in Consents, these improvements are aimed at processes and systems.

There may be constraints on the amount of personnel available to divert assets should a considerably higher than expected wayleave terminations take place during RIIO-ED2, especially if they are clustered together.

These constraints are most likely to affect our capital delivery and networks management teams, and thus could affect the other activities these teams carry out.

We consider that the challenges in this area would be most likely towards the end of the RIIO-ED2 period due to the increase work at this point in ED2, coupled with the uncertainty of consent timescales.

[redacted] To tackle the immediate possibility of many diversions being required, we are developing adaptable workforce plans, taking account of required lead times for scaling up diversion's activity.

SEPD is focused on mitigating risks associated with consents, developing adaptable workforce plans, [redacted] The internal program aims to streamline consent processes to improve efficiency.

SHEPD is addressing similar challenges, with a focus on minimising risks related to consents. SHEPD has also ensured contractors understand delivery priorities and are well-prepared to move forward once contracts are awarded. They have conducted interviews with contractors to assess their ability to manage consent challenges.

Dependency Management

Dependencies, both external and internal, are a critical focus within SSEN's deliverability strategy, ensuring they do not impact the programme timeline. Our approach focuses on early identification, risk assessment, and structured mitigation plans for high-impact dependencies, specifically:

- **Customer Connections**: Given that certain LRE projects rely on customer connections to proceed, SSEN has developed a risk-managed approach to ensure continuity. We have a list of alternative customers prepared to assume these projects if a current connection project experiences a delay, ensuring the LRE project remains viable.
- **Electricity Transmission Network Interfaces**: Modifications from transmission are a dependency for several LRE projects, such as North Hyde, where approval timelines may pose a risk. While awaiting approvals, SSEN continues with non-dependent project work to maintain momentum. This strategy allows us to progress while anticipating that the electricity transmission networks' focus on clearing their backlog will align with government priorities.

In addition to these primary dependencies, SSEN has accounted for various lower-level dependencies that support timely project progression, such as land consents, sub-sea cables, planning applications, and inter-project dependencies.

Through this proactive and adaptable risk management strategy, SSEN maintains its commitment to delivering the LRE programme on schedule and with minimal disruption. Our layered approach, combining early identification, robust contingency planning, and continuous monitoring, ensures that we are well-prepared for any challenges, providing Ofgem with confidence in SSEN's ability to deliver programme objectives reliably and effectively.

9. CONCLUSION

This LRE Re-opener submission outlines our approach to load related expenditure, taking a view out to 2050 to ensure delivery of Net Zero and CP2030 for the communities we serve.

It accounts for the step change in capacity requirements from customers on the SSEN Distribution network since the submission of our ED Business Plan, driven by both demand and generation, and forms part of our plan to enable system optimization. Due to these various changes in external factors, we undertook the reassessment of our load plan, taking a view out to 2050, and using a staged approach to delivery. This potential for uncertainties relating to the developments that have been highlighted are fully accounted for in the modular approach we are taking to deliver our Strategic Development Plans to 2050.

This submission forms our Strategic Needs Case and outlines the three broad categories of projects that we have submitted within Appendix 1:

1) ED2 network compliance schemes;
2) Schemes which need to start in ED2 to complete in ED3; and
3) Access SCR schemes.

All these projects require work to commence in ED2, and over ED2 and ED3 will release more capacity than Ofgem has currently provided funding for.

[redacted]

[redacted] Endorsement of the approach in this submission will give SSEN confidence to continue to commit to these increased fully justified investments in capacity ensuring there is no stop / start in the supply chain thus securing the skills and resources required for efficient delivery. [redacted] compared with 1039 MVA in SEPD and 202 MVA in SHEPD as detailed in the Business Plan Data Tables submitted as part of our ED2 business plan. [redacted]

It is positive that Ofgem has agreed to review our January 2025 LRE UM submission, and we believe that this will simplify the assessment of further LRE UMs in the forthcoming directed additional window driving growth. The endorsement of the approach set out in this UM, would also set a clear framework for LRE network investment into ED3, subject to validation by the RESP, facilitating timely delivery of CP2030.

As requested by Ofgem, we have not submitted the full suite of EJPs that form our load related plan. Instead, we have submitted 10 EJPs in full as part of Ofgem's review of our Strategic Needs Case submission as defined in Appendix 2, to give Ofgem confidence in the approach we are taking in a variety of different contexts, with varying engineering solutions.

We have also included the full list of EJPs that make up the programme of load related expenditure over our baseline allowances in Appendix 3. We have summarized the detail of each of these EJPs, including driver, forecast MVA to be released, forecast MVA release date, forecast spend, and comparison to scope included as part of our ED2 Business Plan submission.

This submission forms *Part 1 – Overarching narrative* aspect of the LRE submission requirements, and our submission in the next additional LRE UM re-opener window that Ofgem will direct will form the *Part 2 – Project specific justification papers* where we will ask for funding based on forecast delivery at that point.[23]

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23 pp. 44-48, Re-opener Guidance and Application Requirements Document, 17 February 2023, 17 February 2023 publication of Associated Documents and relevant issue logs.zip

Summary of Request:

We are seeking the following from Ofgem:

a) a written response with a view on, or acceptance, of our approach to releasing capacity by August 2025 based on the sample set of EJPs, including whether the level of justification provided meets requirements fully or partially;
b) a written commitment by August 2025 that reasonably incurred expenditure will be allowed for developing load schemes and that this expenditure will be treated separately in RIIO-ED3 benchmarking to avoid penalising companies that have spent money developing load schemes;
c) a written response by August 2025 that based on the evidence provided it is fully/partially satisfied that the procurement and delivery approach are in line with best practice and will deliver value to customers;
d) a direction for an additional LRE UM re-opener window in October 2025;
e) a commitment from Ofgem to assess the expected October 2025 submission in accordance with Ofgem's assessment from January 2025 and;
f) a commitment to provide a decision against the October 2025 submission by no later than March 2026.

This is needed for us to commit the required investment to deliver the identified 132kV and 33kV reinforcement schemes that will enable load and generation growth and connections and ahead of forecast constraints and make an investment in capacity [redacted] in the UK economy within the ED2 price control. The alternative would be lack of growth, the inability to confidently secure the supply chain through stop/start regulatory frameworks, and restrictions and lack of confidence in growing the required skills base.

APPENDIX 1 – MEETING OFGEM'S REQUIREMENTS

Ofgem Re-Opener requirements

The following tables set out where we meet Ofgem's Re-Opener Licence and Guidance requirements in this submission.

Table 13: Mapping Ofgem's Re-Opener Licence requirements

Ofgem Re-Opener Licence requirement	Requirement met?	Where / how addressed
Special Condition 3.2 Uncertain Cost Re-openers, Part J Load Related Expenditure Re-opener (LREt) 3.2.75		
(a) the licensee's Load Related Expenditure has increased or is expected to increase, as a result of an increase in: i. current or forecast load-related constraints on the Distribution System that are in place at the time the licensee makes a Load Related Expenditure Re-opener application relative to the constraints associated with the forecast demand used by the Authority to set ex ante allowances for the Price Control Period; or	✓	Business Strategy Alignment; Demonstration of Needs Case; and Deliverability and Risk
ii. the proportion of expenditure associated with load-related constraints on the Distribution System to be funded through Use of System Charges relative to the assumptions used by the Authority to set allowances that are in place at the time the licensee makes a Load Related Expenditure Re-opener application; or	Not applicable	
(b) there is a change in conditions on the Distribution System relative to the assumptions used to set allowances; and	✓	Demonstration of Needs Case
(c) the increase or expected increase in Load Related Expenditure: i. is not provided for by the sum of Load Related Expenditure ex ante non variant allowances specified in Appendix 2, and any previously directed values for LREt and SINVt;	✓	Cost and Regulatory Information
ii. is not provided by the operation of Special Condition 3.9 (Load Related Expenditure Volume Drivers); and	✓	Cost and Regulatory Information
iii. exceeds the Materiality Threshold.	✓	Cost and Regulatory Information

Table 14: Mapping Ofgem's Re-Opener Guidance requirements

Ofgem Re-Opener Guidance requirement	Requirement met?	Where addressed
Needs Case and Preferred Option	✓	Business Strategy Alignment; Demonstration of Needs Case; Consideration of Options Methodology; and Deliverability and Risk. We have also provided sample EJPs which

Ofgem Re-Opener Guidance requirement	Requirement met?	Where addressed
		demonstrate examples of engineering solutions.
Stakeholder Engagement and Whole System Opportunities	✓	Stakeholder and Whole Electricity System Engagement and Opportunities
Cost Information	✓	Cost and Regulatory Information
Cost Benefit Analysis and Engineering Justifications	✓	Demonstrations of Needs Case; Cost and Regulatory Information; Justification of Optioneering; and Deliverability and Risk. We have also provided sample EJPs which demonstrate examples of engineering solutions.

Summary of bilateral engagement

The following table sets out a summary of engagement with Ofgem on the project to date, including Ofgem's feedback on our proposed approach and where we have addressed this feedback.

Table 15: Bilateral engagement on SSEN LRE UM application

Engagement date	Scope	Discussion and outcomes
21 August 2024	Shared our Net Zero First approach, and how our LRE UM submission fits within that.	Methodology; ramp up of demand on network; supply chain considerations; LRE recommendation.
19 September 2024	We provided further detail around how we have reassessed our Load programme of work noting the changes since submission of our RIIO-ED2 Business Plan.	Ofgem stressed that they would not be able to review the full set of EJPs making up the profile of our expected LRE spend over baseline.
03 October 2024	As part of Ofgem Cost Visit.	Ofgem challenged our underspend for the first year of ED2, asking us to provide clear detail around deliverability of our plan in our submission for January 2025.
23 October 2024	Shared our proposal of using January 2025 LRE re-opener window as a Needs Case Submission, and January 2027 window as point for Ofgem to review all EJPs in full. Took Ofgem through two EJPs to demonstrate the approach we are taking.	Ofgem confirmed that they understood that our proposal is for needs case sign off in January 2025, with funding request in January 2027. Said they would want to review a selection of EJPs that present the variety of engineering solutions utilised to enable them to sign off our approach. Ofgem provided verbal guidance on level of detail they would want to see for the summaries of EJPs.
15 November 2024	We shared example information of that which would be included in the list of needs case schemes, shared an overview of our proposed narrative document and discussed how the submissions for January 2025 and January 2027 would work within the parameters of the Re-opener Guidance.	We took action to write up the scope of what Ofgem's needs case approval would cover, We shared this with Ofgem [redacted] Ofgem asked us to consider which EJPs we would submit to ensure they reflect a full range of the technical interventions and solutions. This is reflected in the 10 EJPs we have submitted as part of this application. Ofgem committed to check they are content for our Strategic Needs Case to be viewed as a Part 1 submission under the LRE UM re-

		opener guidance. This was confirmed in Ofgem's email to SSEN [redacted].
13 & 14 January 2025	We met to discuss our intended submission for the January 2025 re-opener window, as well as the timing of a future window, before the existing January 2027, that Ofgem is looking to direct. We discussed the need for our submission to consider the uncertainty of expected policy developments on the optimal LRE investment strategy.	Ofgem confirmed that the agree that we should submit our Strategic Needs Case under the January 2025 Re-opener window as originally planned. Ofgem confirmed they will review this submission and continue to engage with us ahead of our future full LRE UM re-opener submission. We confirmed that our submission will consider the uncertainty of expected policy developments on the optimal LRE investment strategy, as noted by Ofgem. Ofgem confirmed that they will be in touch with DNOs to agree timing for an additional LRE UM re-opener window.

APPENDIX 2 – EJPS

Summaries of sample EJPs

Appendix 2a Denham BSP EJP: Denham 132kV Circuit Reinforcement

The Denham bulk supply point EJP explores a range of solutions aimed at addressing [redacted] network restrictions across the existing 132kV, 22kV and 6.6kV voltage levels in the Denham, Chalfont St Peter, and Gerrards Cross areas. A comprehensive strategy incorporating voltage rationalisation is proposed. The primary focus of this solution is the establishment of a new 33kV voltage level, which will facilitate the necessary network reinforcement required to ensure sufficient network capacity through to 2050. This approach [redacted] considers the wider network requirements so to deliver the most holistic solution. Ultimately, the proposed plan initiates the standardisation of voltage levels and provides a platform for wider network reinforcement.

Appendix 2b Southampton BSP EJP: Southampton BSP Reserve Busbar and 33kV Network

The Southampton BSP reserve busbar and 33kV network EJP explores several complex solutions to address challenges arising across the 132kV, 33kV, and 6.6kV voltage levels within the Southampton urban area, mainly due to the future demand growth in the region and the substantial demand requirement of the ports. A phased strategy is employed, particularly focusing on the development of a new BSP. This approach is driven by the spatial constraints at Southampton BSP, the impracticality of expanding the current site due to its central location, and the challenges associated with securing new land in the required area. The proposed plan considers the long-term requirements of the broader Southampton region to deliver the most holistic and comprehensive solution, [redacted]. Finally, whilst not every reinforcement measure could be deferred through the application of flexibility, it was utilised wherever feasible and cost-effective.

Appendix 2c Salisbury BSP Bemerton EJP: Bemerton 33kV Network

This EJP outlines the strategic recommendations for load-related reinforcement of the Salisbury BSP 33kV network, driven by stakeholder-supported projections in the DFES. It builds upon the RIIO-ED2 EJP (Ref: 156/SEPD/LRE/BEME), which identified the need to reinforce the Bemerton meshed network due to forecasted demand growth during the RIIO-ED2 period. Utilising the CT scenario from the latest DFES, this EJP evaluates and selects the optimal solution to address anticipated thermal overloads, including detailed rationale for options considered.

The proposed solution involves isolating Netherhampton and Petersfinger Primaries from the 33kV meshed network by installing four new underground cables directly from Salisbury BSP. This approach creates dedicated feeder connections, ensuring compliance with Engineering Recommendation P2 standards until at least 2050. Flexibility measures will defer reinforcements and manage constraints, improving net present value (NPV) and optimising planning. Strategic Cost-Benefit Analysis confirms this solution aligns with the UK's decarbonisation targets while upholding network reliability and customer benefits.

Appendix 2d Cowley BSP EJP: Cowley Local Main & Rose Hill Network Reinforcement

This EJP is developed to resolve the network non-compliance issues due to DFES forecasted demand growth in ED2 period on Cowley Local main networks, and on Rose Hill networks. The output includes a large scale of network assets across 11kV, 33kV and 132kV, which will be delivered in different stages during ED2 and ED3 [redacted]. Flexibility is utilised to defer the delivery of the output which is justified via CEM and CBA as the most economic option. The first stage of this project is to replace the existing 11kV switch-board at Rose Hill primary substation to upgrade the 11kV CBs [redacted]. The second stage is to complete all works required at Cowley Local main networks including building a new 132kV GIS busbar, installing the third BSP transformer, and installing a new 132kV circuit from Cowley Local to Cowley. This stage is to be completed by 2028 including one year of flexibility to defer the output. The third stage is to upgrade existing primary 33/11kV transformers at Rose Hill by 2029 including two years of flexibility. The fourth stage is to install two new 33kV cable circuits between Rose Hill and Cowley Local by 2031 including two years of flexibility.

Appendix 2e Iver GSP Uxbridge EJP: Uxbridge Primary Substation Reinforcement

The upgrade of the Uxbridge Primary Substation will be carried out to optimise capacity within the available footprint. Replacing the existing transformers alone will provide sufficient headroom to meet demand growth projections through to 2036. The 11kV switchboard and 66kV circuits will remain unchanged, ensuring the project can be completed with minimal disruption to the community.

Appendix 2f Ealing GSP Harvard Lane EJP: Ealing – Harvard Lane Reinforcement

Harvard Lane Primary Substation EJP outlines plans to address future demand growth in the area by increasing capacity both substation and circuit capacity. The proposed solution involves replacing the transformers and circuits connecting to Ealing Grid Supply Point Substation, bypassing the outdated 22kV Ealing Substation, which will ultimately be retired. This project is expected to more than double the substation's capacity, serving both residential and commercial areas. Furthermore, voltage rationalisation will facilitate the gradual removal of obsolete 22kV assets from the networks.

Appendix 2g Abernethy GSP EJP: Abernethy 33kV Circuit Reinforcement

This EJP outlines the proposal to reinforce the 33kV network between Abernethy GSP, and Milnathort Primary Substation to address the future load-related thermal issues at feeders (306) and (307) under N-1 operating conditions.

[redacted]
The recommended option is the most efficient, and cost-effective solution as per the CEM and CBA, and with the help of stakeholder engagement, whole system approach, and flexibility market analysis. To counter the thermal overload for abnormal network scenarios, the recommended option which utilises the available local flexibility and helps to delay the proposed reinforcement start date by three years.

Our proposed investment at Abernethy GSP, which includes the installation of two new 33kV circuits, will resolve the thermal overload and deliver a compliant network up to at least 2050.

Appendix 2h Burghmuir GSP EJP: BURGHMUIR EJP/SHEPD/INVEE/BUMU/001

This EJP outlines the proposal to reinforce the 33 kV network between Burghmuir GSP, and Inveralmond and Redgorton Primary Substations to address the future load-related thermal issues at Burghmuir feeders (301) and (302) under N-1 operating conditions.

[redacted] The recommended option is the most efficient, and cost-effective solution as per the CEM and CBA, and with the help of stakeholder engagement, whole system approach, and flexibility market analysis. To counter the thermal overload for abnormal network scenarios, the recommended option which utilises the available local flexibility and helps to delay the proposed reinforcement start date by one year.

Our proposed investment at Burghmuir GSP will resolve the thermal overload and deliver a compliant network up to at least 2050.

Appendix 2i Inverness GSP Culloden EJP: CULLODEN EJP_SHEPD_INVE_CILL_001

This EJP outlines the proposal to increase capacity at Culloden Primary Substation. Due to space constrains, the proposal consists of replacing Culloden Primary with a new Primary in the area. This proposed Primary will increase capacity.

[redacted] This paper provides options engineering with the help of stakeholder engagement and a whole system approach. The recommended option is the most efficient, and cost-effective solution as per the CEM and CBA, and with the help of stakeholder engagement, whole system approach, and flexibility market analysis. To counter the thermal overload for abnormal network scenarios, the recommended option which utilises the available local flexibility and helps to delay the proposed reinforcement start date.

Our proposed investment at Culloden Primary will resolve the thermal overload and deliver a compliant network up to at least 2050.

Appendix 2j Keith GSP EJP: Keith 1 33kV Circuits

This EJP outlines the proposal to reinforce the 33 kV network between Keith 1 GSP, and Buckie and Cullen Primary Substations to address the future load-related voltage issues at Keith 1 feeders (303) and (304) under N-1 operating conditions [redacted] The EJP provides relevant information on Keith 1 33kV Circuits in terms of necessary load-related investment within the ED2 price control period.

[redacted] This paper provides options engineering with the help of stakeholder engagement and a whole system approach.

Our proposed investment at Keith 1 GSP will resolve the voltage overload and deliver a compliant network up to at least 2050.

Table 16: External Appendices, EJPs to Demonstrate Investment Approach

Appendix Name	EJP Name	Driver	Engineering Option	License Area	Demonstrates Strategic CBA	Project Timeline (By Price Control Period)
Appendix 2a Denham BSP EJP	Denham 132kV Circuit Reinforcement	CV1	New BSP Substation and Primary Substations' upgrade	SEPD	No	Target Completion in ED2
Appendix 2b Southampton BSP EJP	Southampton BSP Reserve busbar and 33 kV network	CV1	33kV Circuits reinforcement, new BSP Substation	SEPD	No	Start in ED2, Complete in ED3
Appendix 2c Salisbury BSP Bemerton EJP	Bemerton 33kV Network	CV1	33kV Circuits reinforcement and BSP Substation reinforcement	SEPD	Yes	Start in ED2, Complete in ED3
Appendix 2d Cowley BSP EJP	Cowley Local Main & Rose Hill Network Reinforcement	CV1	132kV Circuits upgrade, new BSP Transformers, new PSS Transformers and 33kV Circuits upgrade	SEPD	No	Start in ED2, Complete in ED3
Appendix 2e Iver GSP Uxbridge EJP	Uxbridge Primary Substation	CV1	Transformers upgrade	SEPD	No	Target Completion in ED2

Appendix 2f Ealing GSP Harvard Lane EJP	Ealing – Harvard Lane	CV1	Substation upgrade	SEPD	No	Start in ED2, Complete in ED3
Appendix 2g Abernethy GSP EJP	Abernethy 33kV Circuit Reinforcement	CV1	New 33kV circuits and Primary substations upgrade	SHEPD	No	Target Completion in ED2
Appendix 2h Burghmuir GSP EJP	Burghmuir EJP/SHEPD/INVEE/BUMU/001	CV1	New 33kV switchgear and reinforcement	SHEPD	No	Target Completion in ED2
Appendix 2i Inverness GSP Culloden EJP	Culloden EJP_SHEPD_INVE_CILL_001	CV1	New Primary Substation	SHEPD	Yes	Target Completion in ED2
Appendix 2j Keith GSP EJP	Keith 1 33kV Circuits	CV1	Reconfiguration and reinforcement of the 33kV circuits	SHEPD	No	Target Completion in ED2

Table 17: EJPs which require funding in ED2

EJP Name	Driver	License Area	Project Timeline (By Price Control Period)
33kV AIS - GIS Alton BSP (P)	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Abernethy 33kV Circuit Reinforcement	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Admore GSP, Lochmaddy 33kV New Primary	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Alresford Primary Reinforcement	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Arran 33kV Circuits	CV1 - Primary Reinforcement	SHEPD	Start in ED2, Complete in ED3
Ashton Park EJP	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Barvas 33kV Transformer	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Bemerton 33kV Network	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Bilsham PSS	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Braco West/ Callander 33kV STATCOM	CV1 - Primary Reinforcement	SHEPD	Start in ED2, Complete in ED3
Broadford_Skulamus_33KVCCT	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Brodick -Balliekine	CV1 - Primary Reinforcement	SHEPD	Start in ED2, Complete in ED3
Chichester PSS	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Chippenham BSP 33kV GIS busbar	CV3 - Fault Level Reinforcement	SEPD	Target Completion in ED2
Coll 33kV Transformer	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Coshieville Primary	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Cowley - Yarnton 132kV EJP	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Cowley Local Main & Rose Hill Network Reinforcement	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Denham	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Denham BSP	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3

Drymen and Killin Primary	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Dunvegan GSP	CV1 - Primary Reinforcement	SHEPD	Start in ED2, Complete in ED3
Dyce-Ellon	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Ealing – Harvard Lane	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Ealing 66 kV	CV3 - Fault Level Reinforcement	SEPD	Target Completion in ED2
East Bedfont	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
EJP/SHEPD/HARRIS/001	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
EJP/SHEPD/INVEE/BUMU/001	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
EJP/SHEPD/INVEE/LAXA/001	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
EJP_SHEPD_INVE_CILL_001	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Elgin Ashgrove 33kV Circuits	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Faringdon 33kV circuit reinforcement	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Finstown 33kV Circuits	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Fleet - Fleet Bramley Split (CV25)	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Fleet - PS007705 Tongham 33kV circuit reinforcement	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Fort William 33kV Circuit Reinforcement	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
FORT WILLIAM_SALEN 2_33KVSS_33KVCCTS	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Hunston BSP - Birdham & Selsey Primaries	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Keith 1 33kV Circuits	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Keith 2 33kV Circuits	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Lovedean GSP 132kV Strategy	CV3 - Fault Level Reinforcement	SEPD	Start in ED2, Complete in ED3
Mannington GSP EJP	CV1 - Primary Reinforcement, CV3 - Fault Level Reinforcement	SEPD	Start in ED2, Complete in ED3
Nairn GSP	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Netley Common Thermal Constraints and ringed networks	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
North Hyde Bulk Supply Point (PS008926)	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
North Hyde Primary Substation (PS008855)	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Port Ann GSP	CV1 - Primary Reinforcement	SHEPD	Start in ED2, Complete in ED3
PS003152 - Alton - Fernhurst SCO Reinforcement	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
PS006889 Fleet 132kV GIS	CV3 - Fault Level Reinforcement	SEPD	Start in ED2, Complete in ED3
PS007182 Thatcham 33kV	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
PS009030 Winchester BSP 33kV fault level reinforcement	CV3 - Fault Level Reinforcement	SEPD	Start in ED2, Complete in ED3
PS009162 - Nursling 132kV indooring	CV3 - Fault Level Reinforcement	SEPD	Start in ED2, Complete in ED3

PS009177 COXW 132kV reinforcement	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
PS009211 - Bramley - Thatcham - Amesbury Reinforcement	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Redhill BSP and 132kV Network Reinforcements	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Rownham BSP - Romsey and North Baddesley Primaries	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Slough - Slough South - Chippenham BPSs	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
South Bersted PSS	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Southampton BSP Reserve busbar and 33 kV network	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Stokenchurch EJP	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Stornoway 33kV 305 Circuit Reinforcement	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Tarland Ring	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Taynuilt GSP	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Tummel Bridge/Errochty GSP Integration work	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Uxbridge Primary Substation	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Wareham (Swanage)	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Waterloo Place Primary	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2
Willesden - Park Royal PSS PS008854	CV1 - Primary Reinforcement	SEPD	Start in ED2, Complete in ED3
Witney BSP	CV1 - Primary Reinforcement	SEPD	Target Completion in ED2
Woodhill GSP, Springhill	CV1 - Primary Reinforcement	SHEPD	Target Completion in ED2

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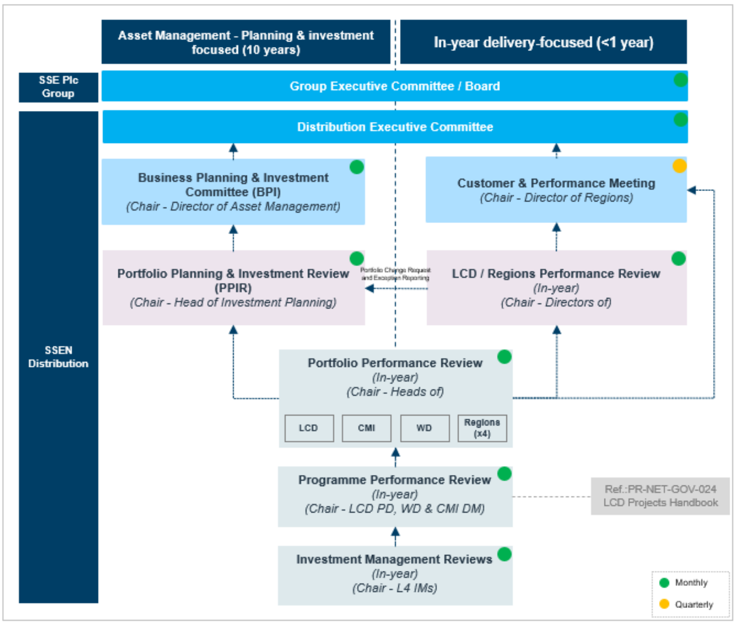
APPENDIX 3 – GOVERNANCE

Figure 18 illustrates our project governance framework which is applied for all of our large capital projects. This is consistent with the high level DGIF process as detailed in Section 5 Stakeholder and Whole Electricity System Engagement and Opportunities.

Figure 18: SSEN Project Governance Framework

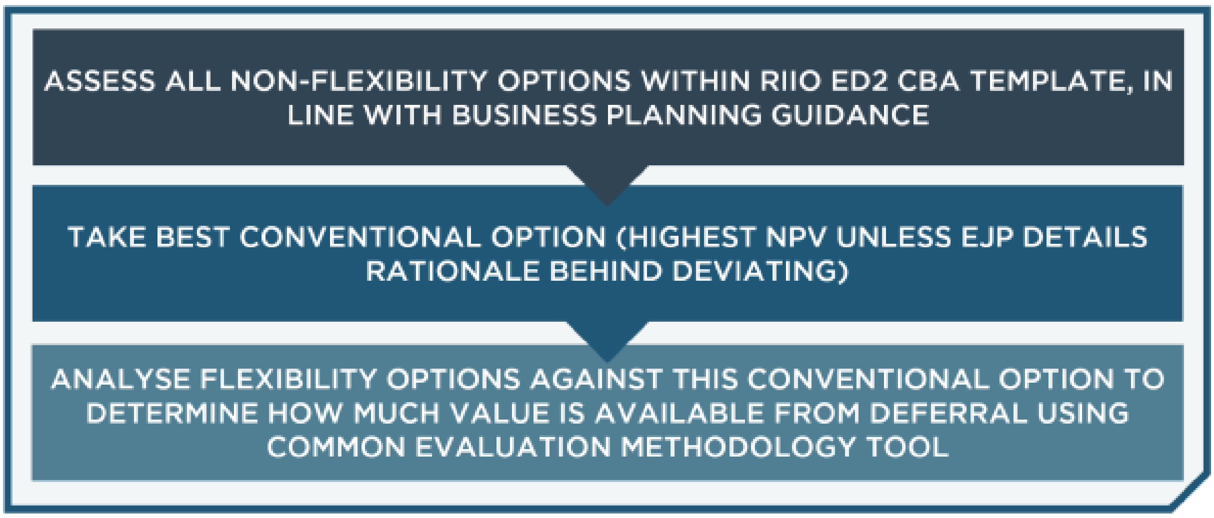


Portfolio Planning & Investment Review (PPIR) Terms of Reference	
Chair	Head of Investment Planning
Core Attendees	• Head of DSO, Head of Asset Planning • Head of Strategy Planning & Sustainability • Head of Finance, Head of Procurement • Portfolio Investment Managers, IDPC Leads • Or delegates
Frequency	Monthly Meeting
Scope	• In-year portfolio performance of cost, schedule and outputs • Portfolio change control for re-prioritisation and optimisation • 6 month look-ahead • ED2 portfolio readiness • ED3 portfolio readiness • ED3 strategy and optimisation plan • Review 'Noted for approval' list of projects for BPI recommendation • Review and report to BPI in-flight overspends / investments exceeding PAT • Recommend items / decisions needing escalation at BPI for approval
Inputs	• Delivery Review charts • ED2 Readiness Plan • ED3 Readiness Plan • IDPC forward-looking plan
Outputs	• 'Noted for approval' BPI list • Governance overspend report • Escalations • PPIR action log

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 Figur9.

Figure 19: 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: RIIO-ED2 CBA Guidance (ofgem.gov.uk).

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; development being led by the Energy Networks Association (ENA), to making decisions about the use of flexibility to defer capital expenditure.

Full guidance on the tool and how it calculates benefits is available at the ENA website: ENA Common Evaluation Methodology v1.0 (energynetworks.org)

Delivery & Outcome Reporting and Monitoring Mechanism

SSEN's DGIF governs the investment decision making process for all SSEN capital projects and programs. The DGIF provides a common understanding to SSEN of the key concepts, templates and tools used throughout the project lifecycle.

The concepts, approaches and processes described in this document are expected to be applied by those responsible for SSEN's capital projects/programmes that create, enhance, or maintain assets. This includes those delivering functional activity in support of the projects.

By adhering to this consistent and repeatable process, decision making requirements will become increasingly standardised and better informed across the organisation, improving the delivery of value for money from investments.

Through adherence to DGIF we ensure a coherent and efficient approach is taken across our delivery projects, synergizing load, connections, and non load work.

APPENDIX 4 – RE-BASELINING OF RIIO-ED2 PLAN

Appendix 4, submitted externally to this narrative document, is a summary of our Strategic Needs Case submission, and includes the EJPs for CV1 and CV3 that are included as part of our LRE plan. It documents the changes to any EJPs that have been revised since inclusion within our RIIO-ED2 business plan, as well as the new EJPs that have been developed, which need work to be either commenced or completed within ED2.

For each EJP key information has been documented, including CV driver, Forecast MVA Released, Date of Forecast MVA released, cost bucket, estimated ED2 proportion, cost included in business plan (if applicable), project driver, and detail around use of flexibility.

APPENDIX 5 – GLOSSARY OF TERMS

Definitions and Abbreviations

Acronym	Definition	Acronym	Definition
BSP	Bulk Supply Point	LHEES	Local Heat and Energy Efficiency Strategies
C	Connections	LRE	Load Related Expenditure
CAM	Coordinated Adjustment Methodology	LV	Low Voltage
CBA	Cost Benefit Analysis	LVSVD	Low Voltage Services Volume Driver
CEM	Common Evaluation Methodology	LtW	Leading the Way
CHP	Combined Heat and Power	MW	Mega Watt
CP2030	Clean Power 2030	MVA	Megavolt Amperes
CT	Consumer Transformation	NARMS	Network Asset Risk Metric
CV	Costs and Volumes	NESO	National Energy System Operator
DEG	Diesel Embedded Generation	NIC	National Infrastructure Commission
DESNZ	Department for Energy Security and Net Zero	NPCA	Non-Price Control Allowance
DFES	Distribution Future Energy Scenarios	ODM	Operational Decision Making
DGIF	Distribution Governance and Investment Framework	Ofgem	Office of Gas and Electricity Markets
DNO	Distribution Network Operator	PCFM	Price Control Financial Model
DNOA	Distribution Network Options Assessment	PCNZ	Powering Customers to Net Zero
DSO	Distribution System Operator	RESP	Regional Energy Strategic Plan
ED2	The second price control in the Electricity Distribution RIIO framework.	RIIO-ED2	The second price control in the Electricity Distribution RIIO framework, where RIIO is Revenue = Incentives + Innovation + Outputs.
ED3	The third price control in the Electricity Distribution RIIO framework.	RIIO-ED3	The third price control in the Electricity Distribution RIIO framework, where RIIO is Revenue = Incentives + Innovation + Outputs.
EJP	Engineering Justification Paper	RRP	Regulatory Reporting Pack
ENA	Energy Networks Association	SAP	Senior Authorised Person
EHV	Extra High Voltage	SCR	Significant Code Review
Elexon	Market Facilitator	SDP	Strategic Development Plan
FY	Financial Year	SEPD	Southern Electric Power Distribution
GSP	Grid Supply Point	SHEPD	Scottish Hydro Electric Power Distribution
GIS	Gas Insulated Switchgear	SHET	Scottish Hydro Electric Transmission
HOWSUM	Hebrides and Orkney Whole System Uncertainty Mechanism	SLC 31E	Standard Licence Condition 31E Procurement and use of Distribution Flexibility Services
HV	High Voltage	SLD	Single Line Diagram

ID	Investment Decision	SROI	Social Return on Investment
JSDL	Joint System Design Liaison	SRVD	Secondary Reinforcement Volume Driver
kV	Kilo Volts	SSEN	Scottish and Southern Electricity Networks Distribution business
LA	Local Authority	ST	System Transformation
LAEP	Local Area Energy Plan	tRESP	Transitional Regional Energy Strategic Plan
LCP	Large Capital Project	TSWP	Tidal Stream Wave Power
LCT	Low Carbon Technology	UM	Uncertainty Mechanism
LENZA	Local Energy Net Zero Accelerator	VFES	Vulnerability Future Energy Scenarios
LHEES	Local Heat and Energy Efficiency Strategies		

CONTACT

Patrick Cassels, Head of Regulation, patrick.cassels@sse.com

Rose Tresidder, Regulation Manager, rose.tresidder@sse.com

Scottish & Southern Electricity Networks