LOAD RELATED EXPENDITURE ANNEX

ED3-S01

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1. EXECUTIVE SUMMARY

Our plan

Electricity demand is entering a period of sustained growth. Electrification of transport and heat, housing and economic development, industrial decarbonisation and new large loads are increasing peak demand.

The challenge for ED3 is to increase capacity whilst protecting customers from unnecessary costs. Our Load Related Expenditure (LRE) Strategy sets out how we will achieve this balance and ensure our network remains an affordable enabler rather than a barrier to growth. Our strategy is about having capacity available where and when customers need it, while avoiding investment ahead of need.

We seek £2.3bn of baseline funding (excluding connections), **£195m through an Agile Contingency Pot and over £700m through targeted uncertainty mechanisms.** This overall £3.3 billion load programme comprises of baseline funding targeted at high-confidence and low-regret requirements, with agile funding and uncertainty mechanisms allowing us to respond quickly where the timing, investment options, or scale of growth remains less certain.

Our programme will deliver over **5,000 MVA of capacity** across SEPD and SHEPD, a **24% increase** to meet ED3 capacity requirements and provide strategic headroom through to 2050. This will support more than 2,900MVA of new demand, facilitating 300,000 heat pumps and more than 2 million electric vehicles.

Our ED3 plan will also release 419MVA of additional capacity for growing demand at high-voltage (HV) secondary substations, enabling more customers to connect and electrify their heating and transport needs. We have established a proactive, programmatic approach to local low-voltage (LV) reinforcement, moving towards coordinated investment in LV mains and customer services. Our proactive LV programme **will increase network readiness from 88% to 92% of customers**, enabling faster adoption of low-carbon technologies and reducing the need for reactive reinforcement. Through our programmatic approach we'll **proactively unloop around 40,000 homes**, representing a fourfold increase compared with ED2, targeted at areas of greatest need and expected to deliver savings of around 10% compared with reactive upgrades.

Our investment has been assessed using SSEN's tRESP-aligned ED3 load forecast. tRESP provides the common strategic pathway while DFES provides the granular spatial distribution needed to allocate those forecasts to individual network assets. The resulting forecast is supplemented with other inputs, including existing demand, contracted connections and Strategic Energy Needs. Full details of SSEN's approach to applying and spatially disaggregating tRESP are provided in the **tRESP Assurance Annex** and associated **Assurance Templates**.

Why intervention is required

Historic demand alone is no longer a sufficient guide to future need. Independent NESO-aligned forecasts show SEPD peak demand approximately doubling by 2050 and SHEPD increasing by approximately 2.5 times. The two networks require different responses: EV uptake in SEPD is already ahead of the national pathway and West London has material data-centre demand, while SHEPD serves a more dispersed network, with 2.5 times more network per customer and emerging demand from heat, hydrogen, ports and distilleries. The current connections pipeline is equivalent to around one-third of today's peak demand.

For every single investment we have carried out detailed analysis: Sensitivity testing and network modelling establish the case for intervention under uncertain demand outcomes, heat-pump uptake sensitivity and incorporating 7 proactive Strategic Energy Needs (SENs) totalling 66.5MW. 82 EHV zones and more than 6,000 secondary assets have also been assessed for flexibility. Whilst we are proposing network reinforcement in areas of high confidence need, we are seeking over 13GW of flexibility over ED3, more than a six-fold increase on ED2 levels. We will use flexibility where it provides better value, manages uncertainty, improves portfolio deliverability and wider system operability. Our baseline plan therefore reflects the maximum-flex position consistent with safety and delivery, while less certain and island

investment is held behind uncertainty mechanisms. If flexibility does not materialise, we will progress with network build, and our Agile contingency pot ensures we can pivot to reinforcement quickly with pre-approved funding. This agility is crucial to ensure we do not become a barrier to new connections.

Our ED2 track record and evidence that ED3 is deliverable

Flexibility has already been established at scale in ED2; early-access products accelerated 1.8 GW of connections with ambitions to increase this to 5GW in ED3. Our ED3 plan identifies c.£195m of customer savings through flexibility deferral, this builds on the foundation of Flexibility First in ED2, where we have matured our flexibility markets and embedded them as a tool to deliver efficient network capacity. Our planning capability is already operational; we refresh our Strategic Development Plans and forecasts annually, these set out the long-term network needs across all drivers (which then feed into our LINP); our LAEP+ (LENZA) tool already has more than 400 users. LV mobilisation has started through a design-by-doing pilot. More than 1,200 surveys have been completed, with further phases testing area-based scope, customer journeys, supply-chain capacity, flexibility and delivery standards. Lastly, our EHV/primary portfolio is already defined at scheme level: we have 175 projects, including 77 detailed EJPs, supported by early design, procurement, framework capacity and integrated outage planning, as set out in our Delivery Strategy.

We mitigate key delivery risks by annually refreshing our Strategic Development Plans, our sensitivity analysis on demand scenarios and use of our agile funding mechanisms if demand develops differently to our forecasts. If flexibility is unavailable of uneconomic we can make use of the agile funding mechanism to ensure we can deliver capacity where and when our customers need it. We are already mobilising the workforce, supply chain and long lead plant we need, in addition to preparing for the consenting, outages and transmission interfaces we will require to deliver our integrated ED3 plan, as set out in our Delivery strategy. Combined with our ED2 LRE UM, our ED3 plan maintains delivery momentum through a period of capacity need, enabling growth and electrification, while protecting customers from the costs of investing either too early or too late.

Customer outcomes, affordability and our accountability

In the past year, we have engaged in over 50 dedicated events, allowing our stakeholders to have their say, and play a key role in shaping our ED3 plan. Customers and stakeholders will receive capacity when and where it is needed, to experience faster connections and have a network that is ready for low-carbon technologies and economic growth. Voltage management and targeted reinforcement will reduce avoidable losses, our ambitious approach to flexibility, proagrammatic plan for LV reinforcement all help to protect customer bills. Place-based prioritisation will use vulnerability evidence so rural, remote and lower-income communities are not left behind, complemented by the shareholder-funded Powering Communities Fund for communities affected by works.

Our delivery will be held to account through the Load Index Risk Metric, uncertainty mechanism volume drivers for secondary-network outputs and project-specific PCDs where proportionate. Our build and flex approach makes this plan adaptable in delivery but specific and accountable in outcome.

Table 1-1 - *ED3 commitments supported by this strategy*

	ED3 Commitment	Metric
Investing for growth and the energy transition		
We will be ready for growing customer demand	**We will expand network capacity by 24%, relative to ED2, to meet local electrification needs and provide strategic headroom through to 2050, alongside proactive upgrades to 40,000 looped supplies, a four-fold increase, targeting areas of greatest need.**	Deliver approximately 40,000 LCT enabled homes through a fourfold increase in LV looped upgrades compared to ED2, targeting the areas of greatest need.
		Release over 5,000MVA on our primary network by 2033 - a 24% increase to meet ED3 capacity requirements and providing strategic headroom through to 2050. This will support more than 2,976MVA of new demand, facilitating 300,000 heat pumps and more than 2 million electric vehicles
		Deliver seven RESP strategic energy needs, identified by NESO's transitional tRESP (as amended by Ofgem)
We will scale flexibility to optimise our network	**We will maximise flexibility to meet customer capacity needs, helping to keep bills as low as possible by using 13.4GW of flexibility through ED3, a six-fold increase on ED2, to accelerate connections and avoid unnecessary investment.**	Utilising 13.4GW of flexibility, providing capacity at lowest possible cost and to avoid delay

2. PURPOSE AND APPLICATION

Our Load Related expenditure annex explains our considerations and processes to determine the investments selected for our plan and the associated load related expenditure. This directly supports the investment decision packs submitted with the plan and should be read in conjunction with our Engineering Justification Papers (EJPs). Common processes and assumptions are set out in this annex rather than in individual EJPs.

In this annex we set out our whole-system planning approach and the inputs used to combine national and regional forecasts with local evidence to identify where, when and how much additional capacity may be needed. In line with Ofgem guidance, we use NESO's Holistic Transition tRESP pathway as our central planning case. This provides a consistent, coordinated route to net zero based on strong electrification, renewable deployment and customer engagement.

Our Distribution Future Energy Scenarios (DFES) add local insight by combining national FES and regional tRESP assumptions with stakeholder evidence, local authority plans, connection activity and emerging customer needs. Updated annually, these forecasts help us identify future demand, generation and storage requirements through to 2050, and assess how network investment, flexibility and local markets could respond.

DFES informs our Strategic Development Plans (SDPs) undertaken by our DSO function, which translate forecasts and local priorities into a long-term, place-based view of how the network may need to develop. SDPs consider needs across the wider network rather than as isolated constraints, providing the foundation for detailed optioneering and investment development.

The planning inputs alongside our strategic planning processes make sure we are progressing low-regret investments and managing more uncertain investments. Via application of our planning processes we have a robust process for selecting where to invest in ED3. Sensitivity analysis is carried out for every single investment, as set out in our Investment Decision Packs and the sensitives identified as part our planning considerations allow us to test our network requirements against alternative LCT uptake scenarios. We can distinguish low-regret investments that remain necessary across credible futures from those that can be deferred or managed flexibly if demand develops more slowly. This helps us to maintain readiness for electrification while protecting customers from premature investment.

The resulting investment identified via this annex is the investment required to create or release network capacity where existing capacity may no longer be sufficient for forecast demand or generation. It includes conventional network reinforcement alongside flexible and smart solutions.

3. STRATEGIC CONTEXT FOR ED3 PLANNING

This section explains the strategic and regulatory context for our ED3 Load Related Expenditure plan and the customer outcomes it is designed to deliver. It sets out how stakeholder evidence, national and regional planning inputs, Strategic Energy Needs, contracted connections and local intelligence are brought together to produce robust licence-area load projections without double counting. It also explains the scope and relationship of our DNO-defined building blocks, the principal drivers of peak demand to 2050 and how sensitivity analysis informs proportionate investment decisions. Together, this evidence supports a plan that enables customers to connect and electrify, targets investment where need is sufficiently evidenced and protects consumers from premature or unnecessary expenditure.

3.1 DELIVERING CUSTOMER OUTCOMES

Our ED3 LRE Strategy is focused on delivering the network capacity customers need to support economic growth and electrification, while maintaining affordability and avoiding unnecessary investment. Our three LRE outcomes reflect this balance: having capacity ready when and where customers need it, investing where there is clear evidence of need, and delivering that capacity efficiently and at long-term value for consumers.

These outcomes directly reflect the priorities we've heard from customers and stakeholders throughout the development of our ED3 plan. Stakeholders have consistently called for sufficient network capacity to support new connections, housing growth, industrial development and the uptake of low-carbon technologies. At the same time, customers expect us to maintain reliability, protect affordability and demonstrate value for money as reliance on electricity increases.

The strength of this priority was reinforced through our ED3 commitment prioritisation: 84% of stakeholders ranked 'Be ready for growing demand' as their highest priority, while 'Scale flexibility to optimise our existing networks' also ranked within the top three of our 12 ED3 commitments. This means two of the three highest-ranked commitments across our ED3 plan directly relate to LRE, reinforcing the importance stakeholders place on both providing capacity for growth and maximising the use of existing network capacity.

Stakeholders were also clear that network readiness must be balanced with affordability and value for money. This creates an important trade-off: investing too early risks customers funding capacity before it is needed, while investing too late risks constraining economic growth, delaying connections and slowing electrification. Our LRE plan is designed to manage this balance and deliver the right capacity at the right time.

We've translated these priorities into three customer outcomes for ED3:

Figure 3-1 - LRE customer outcomes



3.2 EVOLVING OUR APPROACH TO LOAD RELATED INVESTMENT PLANNING

Our load-related planning methodology has evolved considerably over RIIO-ED1 and ED2, reflecting emerging technologies, changing consumer behaviour, evolving policy and differing pathways to net zero. ED3 is the next stage of that evolution, not the end state. While our data, systems and processes evolve to improve the accuracy of our forecasts to inform our investments, uncertainty relating to the scale and location of load growth remains, so a key part of our approach is balancing certainty of need with deliverability and affordability. Our Build and Flex approach is central to this and supports each of our customer outcomes.

How our approach has evolved to deliver our customer outcomes:

- **Enable growth and electrification:** from historic trends to stakeholder-led forecasts. Our enhanced load forecasting process is built on extensive engagement with Local Authorities, communities, developers and major customers, captured in our Distribution Future Energy Scenarios (DFES) and translated into demand and generation forecasts at substation level to 2050. Our DNO building blocks (baseline demand, technology adoption profiles and the contracted connections pipeline) support NESO's transitional Regional Energy Strategic Planning (tRESP) process, helping ensure that forecasts and network plans reflect customer needs. Build and Flex brings flexibility alongside reinforcement as a source of capacity, accelerating customer access while the network is upgraded.
- **Invest with confidence:** from forecast-led to evidence-led investment. tRESP is a significant change in the planning landscape for all DNOs. We've adapted our annual Load Forecast to use its pathway building blocks, Consistent Planning Assumptions and Strategic Energy Needs, assessing a common pathway to 2035, three long-term pathways thereafter and a reduced heat pump sensitivity

developed collaboratively by DNOs. This gives a more consistent basis across network companies and greater confidence in future need. We monitor load and invest at the right time and in the right place, with Build and Flex helping us retain optionality and avoid committing investment where need is inherently uncertain, protecting affordability and reducing the risk of stranded assets, while progressing reinforcement where need is clear or lead times demand early action.

- **Deliver long-term value:** from scheme-by-scheme to strategic, whole-system planning. In ED2, SSEN led the way in developing Strategic Development Plans (SDPs), which give long-term indications of network need and allow constraints to be considered collectively, identifying whole-system options such as new Grid Supply Points, network reconfiguration and resilience programmes. These are enhanced by stakeholder engagement and by work with other network operators to deliver whole-system solutions. Our Network Impact Assessment through the DNOA process then ensures all feasible options are considered, assessing reinforcement, operational and flexibility solutions on whole-life value and balancing consumer and network needs. We see flexibility as a key tool in optimising the deliverability of our overall investment portfolio, helping us sequence what to build now, defer or hold as optionality, considering broader resilience, deliverability and affordability challenges alongside the creation of new capacity for the long-term.

Figure 3-2 below illustrates how these activities and processes have been brought together through our Load Related Expenditure Programme.

Figure 3-2 - LRE end-to-end process



Innovation has played a critical role in developing the planning, forecasting and customer-facing capabilities that underpin our ED3 Load Related Expenditure strategy. During ED2, innovation activities helped improve local energy planning, network visibility, flexibility markets, customer readiness assessment and forecasting methodologies, enabling a transition from reactive network reinforcement towards a more proactive, place-based and data-driven approach to network investment. Building on these capabilities, we will continue to use innovation throughout ED3 to improve forecasting, planning, network readiness and customer engagement, helping ensure capacity is delivered where and when it is needed while maintaining affordability for consumers. Further information is provided in the (ED3-S09) ED3 Innovation Strategy.

Opportunities as our approach matures

- Enduring regional planning. As NESO's enduring Regional Energy Strategic Planning arrangements develop, we can build on tRESP to deepen alignment across network companies and strengthen the link between national pathways and local network need.

- Enhanced engagement and continuous innovation. Continued engagement and improved data can identify emerging demand earlier and improve confidence in its timing. We continue to build on our strong track record within innovation and remain agile to evolving stakeholder needs.
- Greater market participation. As flexibility markets mature, Build and Flex can play a larger role in managing uncertainty and optimising the investment portfolio, with clearer signals for customers and flexibility providers.
- Whole-system coordination. Closer working with other network operators can unlock further whole-system solutions that reduce overall cost and improve resilience.

Proportionate investment under uncertainty

Sensitivities on forecast growth, cost uncertainty and deliverability have been applied throughout to inform the balance between baseline investment and expenditure proposed through uncertainty mechanisms, so that funding requests remain proportionate, evidence-based and adaptable to a more uncertain future.

The expenditure plan set out within this strategy is the culmination of this end-to-end process. It reflects the outputs of stakeholder engagement, load forecasting, network constraint analysis, strategic development planning, flexibility assessment and detailed options appraisal.

A process that will continue to evolve

The ED3 plan is a platform rather than a fixed blueprint. As demand, technology, policy and market evidence change, we'll continue to refine our forecasts, planning inputs and decision-making across ED3 and future price controls. The next section sets out Build and Flex in more detail.

3.3 OUR BUILD AND FLEX STRATEGY

Throughout ED2, we've adopted a flexibility first approach, embedding flexibility as an alternative to reinforcement through our DNOA optioneering processes where it is deemed an economic alternative for a given timeframe. To deliver this approach, we developed the capability to identify flexibility opportunities, engage the market rapidly and deploy solutions that optimise network investment, reducing costs for consumers. Over the past five years, we've grown and matured our flexibility markets, embedding them as a key tool for delivering network capacity efficiently.

We currently offer the broadest range of DSO markets, from three years ahead to day-ahead, to maximise both market liquidity and to support emerging and uncertain needs. Looking to ED3, we're pushing ourselves further, targeting a 95% fill rate of tendered requirements. We've accelerated 1.8 GW of connections through our early access products in ED2, with ambitions to increase this to 5 GW in ED3.

Our Build and Flex strategy in ED3 builds on the progress made in ED2. We're maximising the use of flexibility to provide capacity to customers, at the lowest possible cost and without delay. This enables us to rapidly unlock economic benefit through enabling capacity for industrial, commercial and domestic demands, as part of an expanded set of flexibility use cases. For example, in line with the Scottish Government commitment to explore ways to grow demand for renewable electricity to maximise the local use of Scotland's renewable energy resources, we're identifying locations where demand flexibility measures could be the optimal solution in cost terms for the network and bill-payers, by deferring or reducing the need for particular network upgrades. Our Build and Flex approach supports this through retaining agility and substitutability within our LRE plan to maximise the opportunity for flexibility markets to mature and participate, while making best use of the distribution network in Scotland.

We'll deliver six use cases of flexibility in ED3, with some nuances between application at the higher and lower voltages. In planning, and as described elsewhere in this LRE annex, we use flexibility for efficiency, and to manage uncertainty within load growth projections and deliverability, optimising our investment plan and providing capacity when and where it is needed. Our approach seeks to optimally balance investment

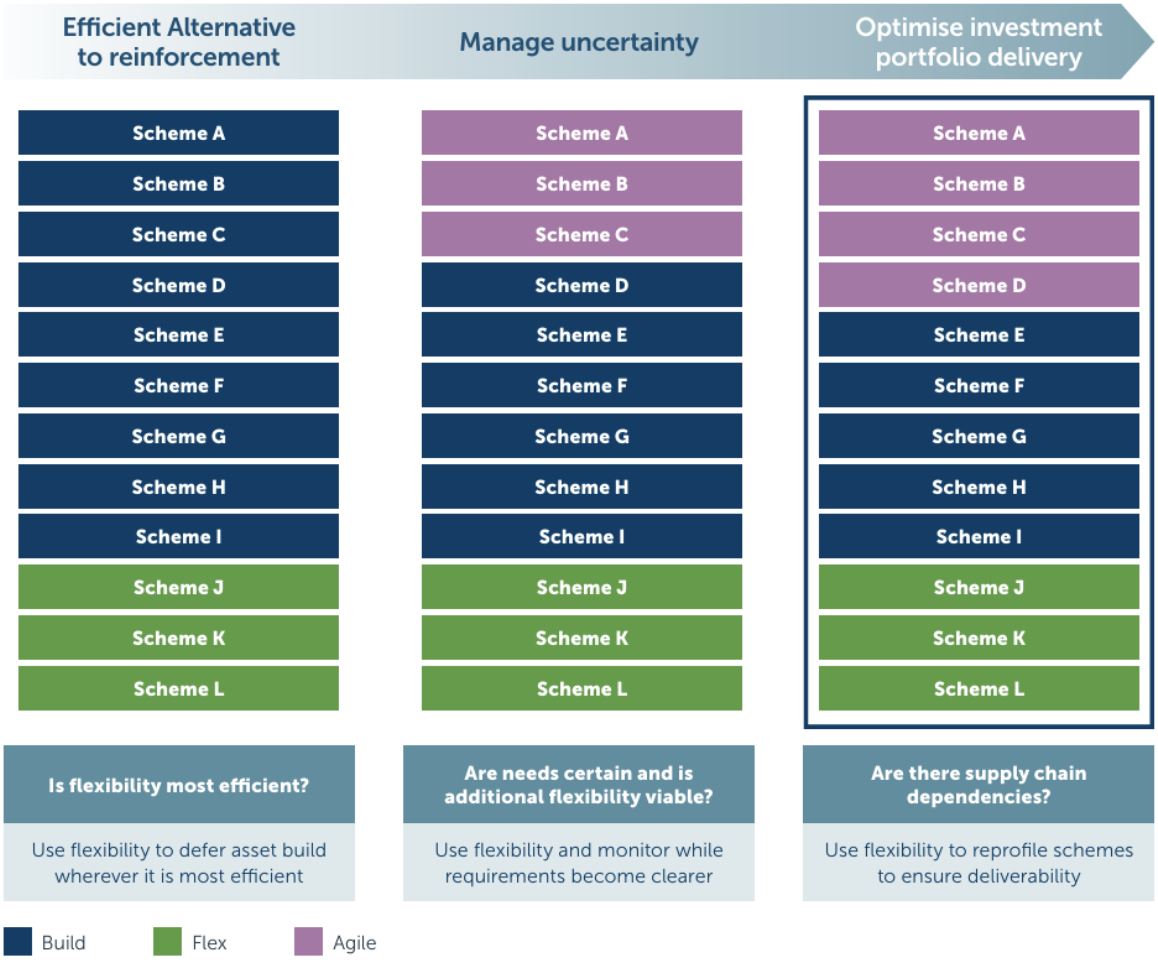
with flexibility, by investing strategically where reinforcements are needed now with high certainty, and maximising flexibility deployment to optimise expenditure and accelerate capacity wherever feasible and economic.

As detailed in Figure 3-3, in optimising our load related expenditure portfolio, we consider:

- The certainty of needs
- The viability of flexibility
- The deliverability of the wider portfolio

This includes the sequencing of works and our ability to maintain network integrity and resilience while providing capacity when, and where it's needed.

Figure 3-3 - Optimising Build and Flex



This is complemented by our use of flexibility to support network operations that drive whole system outcomes, accelerating network access and minimising disruption where it is a viable and economic alternative, as described in our (ED3-S10) DSO Strategy.

4. LONG-TERM ENERGY PROJECTIONS

This section presents our evidence-based view of how electricity demand may develop across the SEPD and SHEPD licence areas through ED3 and to 2050. It explains the central planning inputs, assumptions and locally evidenced demand drivers used in our projections, including low-carbon technology uptake, contracted connections, Strategic Energy Needs and industrial decarbonisation. It compares the principal contributors to peak demand, identifies material regional differences and shows how sensitivities, including

alternative heat-pump uptake, are used to test the timing and robustness of investment need. This gives customers confidence that network plans reflect credible future requirements while retaining flexibility where the pace or location of growth remains uncertain.

4.1 KEY TRENDS AND PLANNING IMPLICATIONS

Our LRE strategy must respond to a range of social, economic and policy trends that will shape future network requirements. These trends are reflected within both our forecasting assumptions and investment decisions as summarised below:

Table 4-1 - Key trends and planning implications

Trend	Impact on ED3 planning	Strategic response
Industrial electrification and economic growth	Creates significant future demand growth and new capacity requirements.	Use DFES, tRESP Strategic Energy Needs, stakeholder intelligence and long-term forecasting to identify needs early.
Supply chain constraints	Longer lead times increase delivery risk and can affect investment timing.	Earlier project development, portfolio planning, strategic procurement and use of flexibility where appropriate.
Consumer participation and LCT uptake	Increasing EV, heat pump, solar and flexibility adoption changes network loading patterns.	Enhanced forecasting, LV planning and readiness programmes supported by local intelligence and stakeholder evidence.
Increasing resilience expectations	Greater reliance on electricity increases the consequence of outages.	Target resilience-focused investment, network reinforcement and coordinated system planning.

4.2 CENTRALISED PLANNING INPUTS

The energy sector has recently undergone a shift towards more strategic and coordinated planning across national, regional and local levels. This is intended to accelerate the infrastructure investment required to support economic growth and decarbonisation, while providing greater certainty to network companies, customers and wider stakeholders.

Through the Sector Specific Methodology Consultation (SSMC) and subsequent Sector Specific Methodology Decision (SSMD), Ofgem established the framework for ED3 planning and set expectations for how DNOs should develop and justify load-related investment proposals. This includes the use of consistent planning assumptions, regional strategic planning outputs and transparent approaches to managing uncertainty and affordability.

A key element of this framework is the enhanced role of NESO in strategic energy planning. The transitional Regional Energy Strategic Plans (tRESPs), together with Strategic Energy Needs (SENs) and Consistent Planning Assumptions (CPAs), provide a common evidence base for forecasting future network requirements and identifying where capacity will be required. Our ED3 load plan adopts these outputs as its

primary planning baseline and the next section summarises the process we adopted. In addition, you can also view our tRESP assurance process and template, with the full detail of how we accommodated the CPAs and SENs (including those NESO deemed proactive), as an addendum to the Business Plan submission.

As such, our plan is founded on a shared planning process undertaken with NESO, other DNOs and a wide range of regional and national stakeholders. The pathways, assumptions and Strategic Energy Needs (SEN) identified through the tRESP process are a key driver of our forecast requirements and investment proposals, helping to ensure that network development is coordinated across the wider energy system.

4.3 STRATEGIC ENERGY NEEDS

4.3.1 OVERVIEW

Strategic Energy Needs (SENs) identified through the tRESP process represent potential future sources of significant electricity demand that may require network investment ahead of traditional customer-led triggers. While SENs form one of the planning inputs to our licence area load projections, not all identified SENs justify proactive investment within ED3. This section describes the process used to assess the plausibility of proactive investment SENs, validate underlying assumptions, and determine which projects should be reflected within our forecasting, network studies and investment plans.

The purpose of this assessment is to determine whether sufficient evidence exists to support proactive investment during ED3 and to ensure that only credible and well-evidenced requirements are incorporated into our Load Related Expenditure (LRE) plan.

The assessment has been undertaken in accordance with Ofgem and NESO guidance and forms part of the evidence supporting our ED3 investment proposals. It enables us to distinguish between projects where proactive investment is justified and those that are more appropriately managed through future planning cycles or uncertainty mechanisms.

4.3.2 ASSESSMENT METHODOLOGY

All proactive investment SENs were assessed through a structured three-stage process, as shown in the table below.

Table 4-2 - proactive investment SENs assessment methodology

Stage	Purpose	Outcome
1. Categorisation	Review the SEN classification assigned through the tRESP process.	Classify projects as: • Early-stage • Strategic National or Regional Need • Proactive Investment Need
2. Validation	Review project maturity, customer evidence, connection status and interaction with wider planning assumptions.	Confirm that projects: • Remain relevant for ED3 planning • Are not already committed connections • Require distribution network intervention
3. Plausibility assessment	Review current project maturity, consenting and financing status.	Update the project plausibility grade using current consenting and financing evidence.

1. Strategic Energy Need Categories

The tRESP identifies three categories of Strategic Energy Need:

A) Early-stage needs

These projects are generally not expected to drive ED3 distribution investment requirements. They are treated as potential future requirements and are monitored through future planning cycles unless additional evidence demonstrates a more immediate network need.

B) Strategic national or regional needs

These projects may be strategically important to the wider region or nation but do not automatically justify proactive investment. We reviewed these projects to determine whether additional evidence existed to support their inclusion within our licence area demand forecasts and network studies.

C) Proactive investment needs

Projects identified by NESO as requiring proactive investment were subject to detailed validation. These projects formed the primary focus of our validation process and plausibility assessment.

2. Validation Process

For each proactive investment SEN we undertook a structured validation process. We reviewed:

- Project location;
- Appropriateness for distribution network intervention;
- Expected connection date;
- Anticipated electricity demand profile;
- Interaction with existing contracted connections;
- Interaction with DFES and tRESP pathways;
- Interaction with other identified SENs;
- Likely network impacts;
- Likely reinforcement requirements; and
- Evidence provided by project developers and stakeholders.

This process included engagement with developers where appropriate and ensured consistency with the wider forecasting methodology described in **Section 1.5**.

To avoid double counting, all projects were reviewed against existing tRESP pathways and contracted connections before being incorporated into planning assumptions. Projects already represented elsewhere within the forecasting framework were removed from further consideration.

3. Plausibility Classification Framework

Consistent with Ofgem guidance, each proactive investment SEN has been assessed against two principal criteria:

- Planning and consenting maturity; and
- Evidence of financing and project commitment.

Projects are classified as follows:

Table 4-3 - Plausibility classification framework

Plausibility	Projects with:
High plausibility	▪ Planning consents secured, or existing consents already covering the development; ▪ Financing arrangement finalised
Medium plausibility	▪ Planning applications submitted or advanced through the consenting process

	▪ Material financing progress
Low plausibility	▪ Early-stage planning status ▪ Limited evidence of financial commitment

In accordance with Ofgem ED3 Business Plan Guidance (para 3.34), SENs were deemed to have failed validation if they did not respond to our assessment request[1].

4.3.3 ASSESSMENT OUTCOMES

Our assessment identified a range of project maturities and delivery confidence levels across the proactive investment SEN portfolio. Projects assessed as high plausibility demonstrated strong evidence of planning progress, financing commitment and delivery confidence. These projects provide the greatest confidence that network investment may be required during ED3 and therefore warrant inclusion within our planning assumptions, subject to network impact assessment and optioneering to determine the appropriate investment response.

Projects assessed as medium plausibility demonstrated credible progress but retained some uncertainty around delivery timing or scope. These projects continue to be monitored through our planning processes and may become candidates for future investment as evidence matures. Two medium plausibility projects have been considered in network planning. The justification and evidence for including proactive investment advance for these projects can be found in Appendix 1.

Projects assessed as low plausibility remain under review but currently lack sufficient evidence to justify proactive network investment during ED3.

Our assessment concluded with five SENs incorporated into network planning consideration within our SEPD licence area, totalling 57 MW. In SHEPD, we considered two SENs totalling 9.5 MW in our network planning. All SENs modelled within our analysis are within areas of investment over the ED3 period. Full detail of our SENs can be found in Appendix 1.

4.3.4 INTEGRATION INTO THE ED3 PLAN

The plausibility assessment is used to inform forecasting assumptions, network impact assessments and investment planning activities. Where a proactive investment SEN is considered sufficiently credible and likely to impact network requirements within the ED3 planning horizon, it is incorporated into network studies and optioneering assessments. Reinforcement options are evaluated alongside flexibility solutions, delivery requirements, affordability considerations and future demand scenarios to identify the most efficient outcome for consumers.

The outcomes of the plausibility assessment also inform how future requirements are treated within the ED3 plan. Higher-plausibility projects provide greater confidence in the timing and scale of future demand growth and therefore support consideration within baseline investment proposals where intervention is required during ED3. Projects with lower levels of certainty continue to inform longer-term planning activities and may be more appropriately managed through future planning cycles or uncertainty mechanisms as additional evidence emerges.

This approach ensures that proactive investment is targeted towards the most credible and material future network requirements while retaining flexibility to respond to changing customer requirements, project development and wider economic growth.

[1] ED3 Business Plan Guidance

4.4 DNO DEFINED BUILDING BLOCKS

4.4.1 OVERVIEW

The tRESP Holistic Transition pathway provides the primary planning baseline for our ED3 licence area load projections. However, distribution network planning requires additional regional and local information to ensure future network requirements are appropriately reflected within forecasting and network investment decisions.

To develop licence area load projections suitable for network planning, we supplement the tRESP baseline with a number of DNO-defined building blocks. These building blocks capture local information, customer commitments and demand drivers that are material to future network requirements within our SEPD and SHEPD licence areas.

The purpose of these building blocks is not to replace the tRESP framework, but to complement it by incorporating evidence that is either more location-specific, more up-to-date, or more reflective of local circumstances. Together, the tRESP baseline and DNO-defined building blocks provide our current best view of future demand and form the basis of the network impact assessments and investment proposals set out in **section 5.1**

A key principle of our forecasting methodology is that future demand should only be represented once. All DNO-defined building blocks are therefore reviewed against tRESP assumptions, Strategic Energy Needs (SENs), contracted connections and other planning inputs before inclusion within licence area load projections to avoid double counting. This geographic reconciliation process enables SSEN to combine national planning assumptions with local intelligence while maintaining a consistent and auditable forecast of future electricity demand.

4.4.2 DNO-DEFINED BUILDING BLOCKS

Table 4-4 summarises the DNO-defined building blocks used within our ED3 forecasting methodology and their relationship with the tRESP framework.

Table 4-4 - DNO-defined building block

DNO-defined building block	Purpose	Relationship with tRESP baseline
Historic and existing network demand	Provides the baseline level of electricity demand from which future growth is forecast. Based on recorded network demand and observed customer behaviour.	Forms the starting point for applying tRESP pathway growth. Baseline figures are assumed connected within existing demand.
Contracted connections	Reflects customers that have secured network capacity and therefore represent a higher-confidence indicator of future demand.	Supplements pathway assumptions with committed customer requirements. Projects already represented within SENs or other inputs are removed to avoid duplication.
Distribution Future Energy Scenarios (DFES)	Provides regional insight into future technology uptake, sector growth and emerging local demand drivers.	Provides additional regional context and local intelligence to support interpretation and validation of the tRESP baseline. DFES Building Blocks from BSP to LV level are scaled to tRESP GSP data to ensure consistency.
Strategic Energy Needs (SENs)	Represents strategically important projects that may create material demand growth within our licence areas.	SENs are subject to the plausibility assessment described in 4.3.2 before

		inclusion within forecasts and network studies.
Stakeholder and local planning evidence	Draws on intelligence from Local Authorities, LAEPs, Strategic Development Plans, developers, major customers and wider stakeholder engagement.	Provides local context and informs the interpretation of national planning assumptions.
Strategic industrial and economic developments	Captures large demand drivers that may not be fully reflected through historic trends or national datasets, including industrial decarbonisation projects, ports, hydrogen developments and data centres.	Assessed against SENs, contracted connections and tRESP assumptions before inclusion.

Translating building blocks to network forecasts

The DNO-defined building blocks described above are combined with the tRESP planning baseline to develop SSEN's licence area load projections.

These projections are subsequently translated into electricity demand profiles and forecasts across all voltages using the energy load assumptions described in the following section. This enables future demand to be assessed at asset level, identifies where network constraints are expected to emerge, and provides the evidence base for the investment requirements included within our ED3 Load Related Expenditure plan.

Appropriateness of Data sources

In selecting DNO-defined building blocks and associated assumptions, we considered:

- Reliability and quality of source data;
- Relevance to electricity network planning;
- Currency of information;
- Capital granularity;
- Seasonal and temporal characteristics; and
- Expected future evolution of the underlying demand driver.

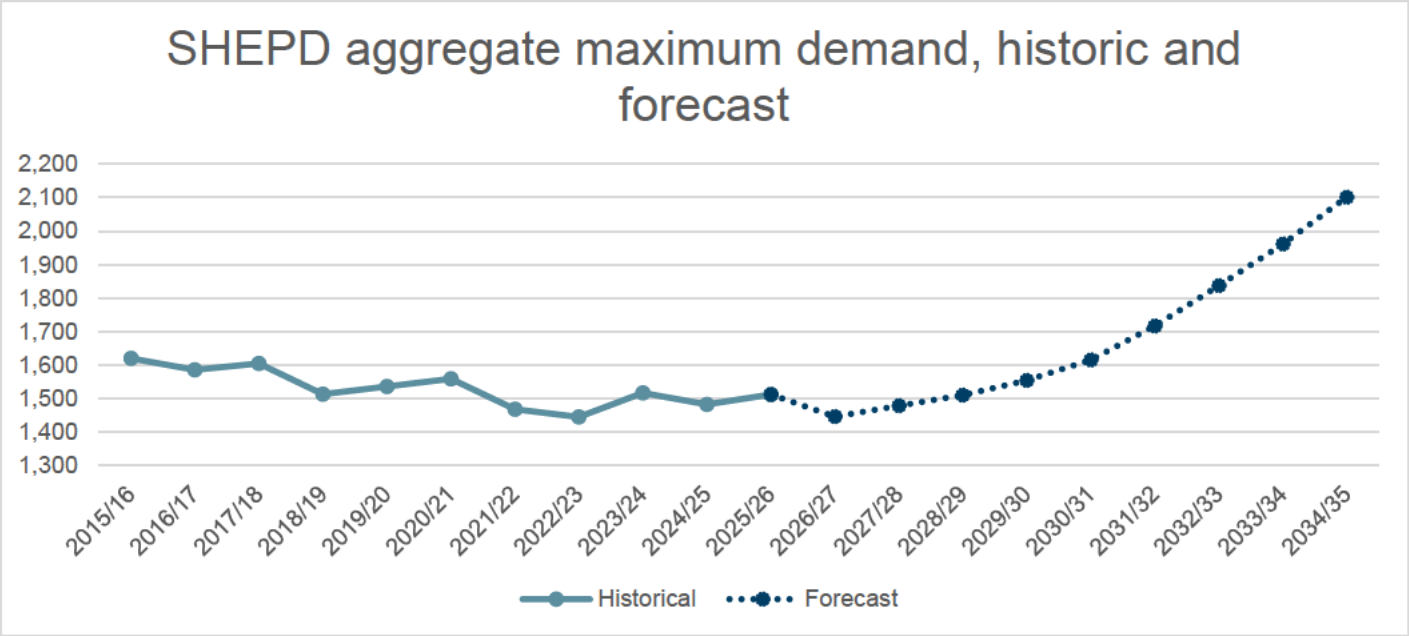
Together, these data sources provide a robust and evidence-based foundation for the development of licence area load projections and the identification of future network requirements across both licence areas.

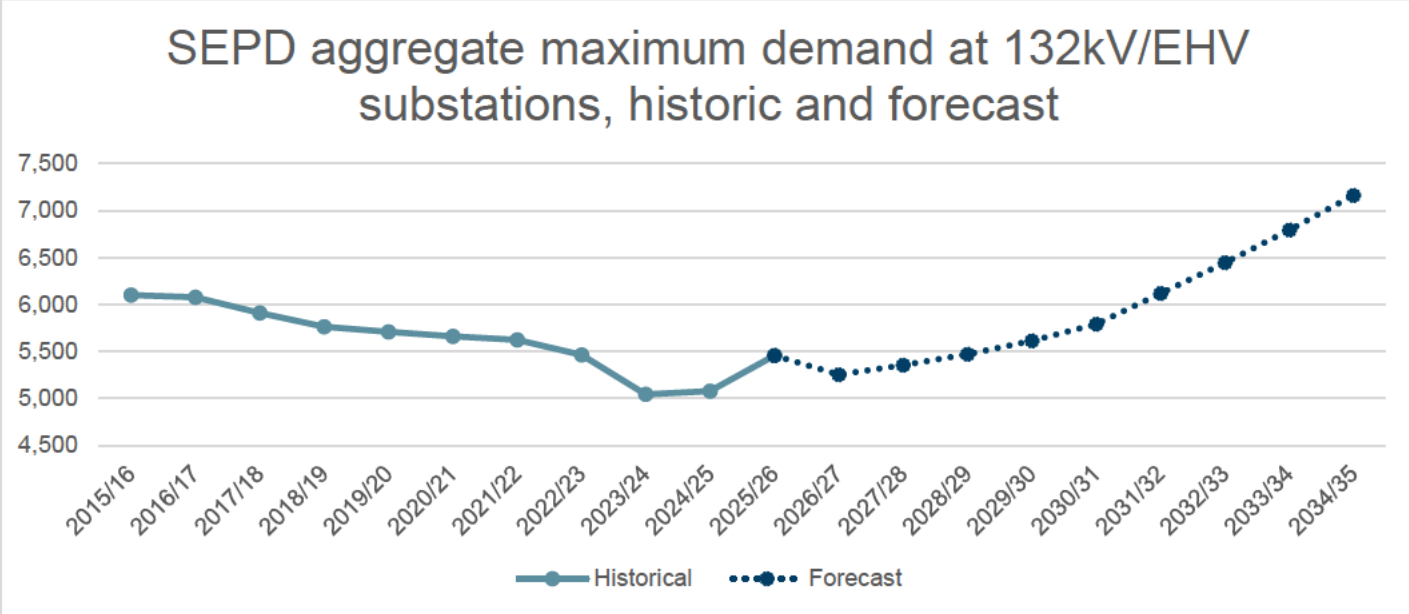
In ED2 we developed our Data Quality Dashboard and invested in our 'Network Model Manager' (NMM) system. This combines our IT and OT data and systems into a single source of the truth for planning and operational activities, while our Data Quality dashboard reports on the quality, accuracy and completeness of all our published data sources for transparency. This provides both our internal colleagues and external stakeholders with confidence in the data that we use to develop our network investment plans. Through the final years of ED2, as committed within our DSO Action Plan, we are targeting 100% data completeness and accuracy, and will report on this via quarterly KPIs.

4.4.3 HISTORIC DEMAND AND FUTURE NETWORK REQUIREMENTS

Historic network demand provides an important starting point for our load forecasting and helps us understand how network utilisation has changed over time. However, historic trends alone are not sufficient to determine future network needs. As Figure 4-1 illustrates, the demand outlook across both SHEPD and SEPD represents a clear change from the historic trajectory, with increasing demand expected over the forecast period.

Figure 4-1 - aggregate maximum demands (historic and forecast)





This changing profile reflects demand drivers that may not yet be fully observable through historic network loading, including the electrification of heat and transport, new customer connections, and wider strategic and economic development. The scale, timing and location of this growth will also vary across our networks, meaning future demand cannot simply be determined by extrapolating historic trends.

For a full view of our historic demand at substation level, please refer to **Appendix 2**.

4.4.4 DFES / tRESP

A key part of DSO's strategic planning process is understanding how communities' needs of the network will evolve moving forward. To understand these trends, we partner with Regen to produce our Distribution Future Energy Scenarios, or DFES. In this annual process, we forecast future load growth (both demand and generation) on our network in four societal and consumer transformation scenarios to 2050, using stakeholder input as a key data infeed.

Our DFES forecasts help us understand when, where, and how many new connections we can anticipate in different pathways to net zero by 2045 in Scotland and 2050 in England. These forecasts also serve as a key input to our strategic network investment process, which you can read more about on our Strategic Development Plan webpage.

The DFES analysis produces high-granularity forecasts for the growth and reduction of electricity generation, demand and storage technologies connecting to SSEN's electricity distribution network including the relevant profiling and spatial allocation of future demands across our licence areas. Underpinning the DFES analysis is the National Energy System Operator's (NESO) Future Energy Scenarios (FES) and tRESP framework.

These frameworks outline different scenarios for the future of the whole energy system, mapped to the Grid Supply Point (GSP). The overarching assumptions that define these scenarios are integral to the DFES analysis, however DFES provides the local, bottom-up view of future energy projections from the lower voltages which in turn informs future iterations of the FES and tRESP. The full DFES suite of documents and methodology can be found here.

The DFES 2025 analysis was provided by SSEN as an input to NESO for the development of tRESP, which was published in early 2026. The tRESP components have been considered in the DFES analysis in a few different ways:

- The tRESP technology building blocks were already closely aligned to the DFES building blocks. The potential for analysis to be aggregated up for comparison/reconciliation hinges on the granularity of the projections being at the same level.
- The interim CPAs provided by NESO for EVs and heat pumps were considered in the equivalent DFES 2025 modelling assumptions.
- The future net zero pathways for the building blocks published in early 2026 have been interrogated and reconciled to the DFES projections at SSEN's network level.

Further detail on tRESP assumptions is provided within the tRESP assurance annex.

SSEN uses the localised DFES analysis, scaled by NESO's tRESP outputs as part of an integrated network planning, optioneering and investment appraisal process. The tRESP projections enable SSEN to model changes to future electricity demand across the network and subsequently assess where network improvements are needed to ensure the capacity is available to meet future demand and deliver government ambitions for both Clean Power 2030 and net zero by 2050.

4.4.5 CONTRACTED CONNECTIONS

While the tRESP provides the primary foundation for identifying future network requirements, it must be complemented by more granular and up-to-date local information.

The connections queue provides one of the strongest indicators of future capacity requirements, reflecting customers that have formally requested network capacity to support new demand or generation projects. These applications provide direct evidence of emerging network needs and are therefore an important input to our planning process. However, experience shows that not all projects progress to delivery, meaning that queue data must be assessed carefully alongside wider evidence when determining efficient levels of investment.

The impact of new connections on monitored demand and generation can often be less than the contracted figure accepted by the customer. To avoid overestimating the load of new connections, we apply an evidence-based ruleset to reduce the impact where applicable. This approach, along with attrition level, is something we continue to refine, supporting the overall accuracy of forward-looking forecasts. Innovation projects such as Seachange, which was focused on maritime decarbonisation, and Fortress, focused on

NHS decarbonisation, can help us understand future needs. If this process results in an under-forecast, we've developed a range of access products to enable earlier connection and remove uncertainty.

Where connections confidence is high, network build is progressed, however where uncertainty remains on the volume, scale and location of new connections and their aggregate impact, we'll utilise flexibility and offer early Access Products to our customers so as not to delay access onto our network. Within our (ED3-S10) DSO strategy, we commit to making suitable products available to 85% of both demand and generation customers seeking a new connection.

Our approach has been informed by our Innovation project Fasttrack, which uses a data-driven planning and visualisation tool that uses probabilistic forecasting to improve how electricity networks assess the likelihood of connection requests proceeding and how this can be "summed" up across multiple voltage levels and locations. This produces a risk-based future demand forecast to enable a better-informed use of early Access Products to enable customers to connect more quickly. Through this approach, we're forecasting to offer of earlier-access options to more than 5 GW of connection capacity and deliver at least 2.5 GW-years of accelerated connections over ED3 to ensure that we maintain our commitment to deliver capacity to customers when and where they need it.

Alongside connections data, we utilise insights gathered through our Strategic Development Plans (SDPs), together with evidence from Local Area Energy Plans (LAEPs), Local Heat and Energy Efficiency Strategies (LHEES), Local Authority engagement and wider regional stakeholder discussions. These sources provide additional intelligence on emerging growth ambitions, decarbonisation plans and local priorities that may not yet be visible through national planning datasets.

Together, these inputs enable us to supplement and refine the tRESP outputs, ensuring that national strategic planning assumptions remain grounded in local circumstances and customer needs. The following sections explain how these inputs are incorporated into our forecasting methodology including DNO-defined building blocks and Strategic Energy Need assessments to develop a robust and evidence-based view of future network requirements.

4.4.6 STRATEGIC INDUSTRIAL AND ECONOMIC DEMAND DRIVERS

Strategic industrial and economic developments form one of the DNO-defined building blocks used to supplement the tRESP baseline. These developments are considered separately because they can create significant, location-specific increases in electricity demand that may not be fully reflected within historic trends, national forecasting assumptions or contracted customer demand. This section explains how these developments have been considered within our forecasting methodology and how any interaction with Strategic Energy Needs (SENs) has been managed.

Key sectors driving demand

In addition to demand growth associated with the electrification of heat and transport, our forecasting process considers strategic developments that may materially affect future network requirements and create significant step changes in electricity demand.

Key drivers considered include:

- Strategic Energy Needs identified through tRESP;
- Major commercial and industrial developments;
- Industrial decarbonisation projects;
- Hydrogen-related developments;
- Data centre growth;
- Large-scale generation and storage projects; and
- Wider regional economic growth initiatives.

Consideration has been given to the increased scaling of electrification of industrial processes and the emergence of large strategic loads such as data centres. These developments have the potential to create significant localised network requirements and therefore require specific assessment within our planning methodology.

We also draw on our suite of innovation projects looking at future demand in sectors that are seeking to electrify (see Table 4-5). Through these projects we have engaged with relevant stakeholder groups including the British Ports Association, NFU Scotland and NHS England to inform assumptions around the scale and pace of future demand, with learnings being incorporated into out forecasting approach.

Table 4-5 - Innovation projects

Innovation project	Sector application
SeaChange	Develops a data-driven approach to support the decarbonisation of ports and the wider maritime sector by improving visibility of future electricity demand.
FORTRESS	Flexibility and Optimisation for Resilience in Energy Systems - Explores how critical and protected sites, such as hospitals, can decarbonise while maintaining resilience and essential services.
DIME	Demand Insights for Metered Enterprises - Addresses a critical visibility gap in small and medium enterprises (SMEs) electricity demand where half-hourly data is not available to improve low-voltage network planning.
FARM	Future Agriculture Resilience Mapping - Explores how future energy demand from food production could change as agriculture decarbonises, and how distribution networks should plan for this.
RIDES	Rural Industrial Decarbonisation Energy Scenarios - Develops a data-driven tool to help rural industrial sites plan their decarbonisation pathways while giving network operators clearer visibility of future demand.

Alongside this we have the ‘Fasttrack’ project which uses a data-driven planning and visualisation tool that uses probabilistic forecasting to improve how electricity networks assess the likelihood of connection requests proceeding and how this can be "summed" up across multiple voltage levels and locations. This produces a risk-based future demand forecast to enable a better-informed use of early Access Products to enable customers to connect more quickly.

To maintain consistency with the tRESP methodology, future demand forecasts incorporate contracted connection demand and Strategic Energy Needs (SENs). Wider industrial and economic developments are monitored to inform network planning and future forecast development but are not included within demand forecasts unless they meet the relevant evidence thresholds and assessment criteria.

Approach to industrial decarbonisation in ED3 planning

Our Strategic Development process facilitates regular engagement with placed-based stakeholders including Local Authorities and industrial users. Through this engagement we gather insights on industrial decarbonisation for consideration in our long-term strategic plans. We used the information gathered in 2024 and early 2025 as the basis for submissions to NESO's Strategic Energy Needs Request for Information which resulted in SSEN submitting 18 applications for consideration of SEN in the tRESP process. These included applications relating to industrial decarbonisation from a range of industries including distillery, port, hydrogen, manufacturing and transport. In all cases SSEN discussed the application with the developer to ensure we had the latest information for the tRESP process. In many cases discussions included longer-term projections but often these carried too much uncertainty regarding the pace of development to be progressed through the t-RESP process. We do however continue to consider such developments in our longer-term strategic development process.

The tRESPs were subsequently published in January 2026 which provided further insights from parties who had engaged directly with NESO. Where strategic developments overlap with existing tRESP assumptions or SENs, projects are reviewed before inclusion to ensure future demand is not double counted.

We have reviewed SENs through the plausibility assessment described in 4.3.2 including those relating to industrial decarbonisation. This has consolidated the list and, while there are several standalone SEN, there are two defined clusters;

- **Oxfordshire SEN** – these relate to future demands in the Oxford and Bicester areas which are both driving investment needs relating to infrastructure within both Cowley and East Claydon GSPs. There is also significant housing growth in this area.
- **Inverness SEN** – these SENs reflect the insights and information we have gathered through our strategic planning processes as documented in the Inverness and Aviemore SDP[2].

SEN projects that do not have sufficient maturity and/or certainty to meet consideration in our ED3 submission have been retained and are used to inform our strategic planning processes going forward. This will allow us to ensure we're continuing to strategically develop our networks to meet future needs. This includes most projects that SSEN submitted to NESO in 2025 with only one being subsequently categorised as warranting consideration for proactive investment needs.

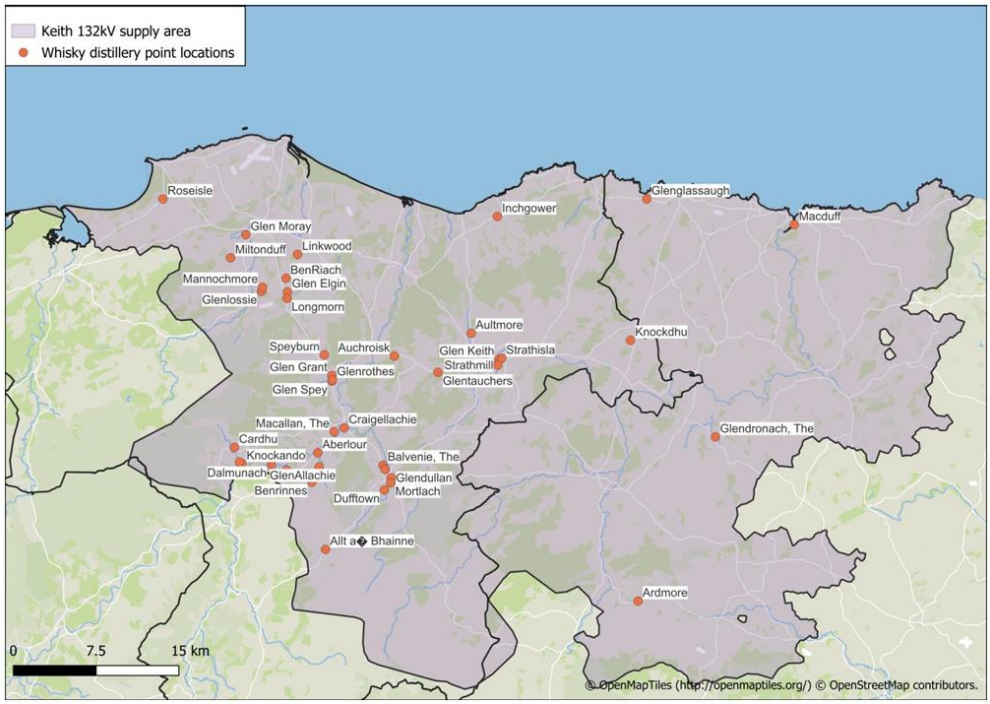
In particular, we would identify the following sectors where we're seeing significant growth:

- **The Scottish Distillery Industry –** This sector needs significant energy for the distillation process and there is clear movement to decarbonisation of their operations. While some of this may be managed through hydrogen, there is clear appetite for electrical heating as a solution particularly if there is network capacity available to meet their needs. The Scotch Whisky Association (SWA) has set an ambitious target to decarbonise its operations by 2040 and achieve net zero emissions across the Scotch whisky industry by 2045, aligning with broader climate goals and driving sustainability throughout its supply chain. Key areas include Islay and Jura (covered in greater detail in our (ED3-S17) Islands Strategy)) and Speyside where there are over 55 distilleries in the region. Our preliminary findings suggest that the additional load from whisky decarbonisation could rise by up to 90 MVA in the Keith GSP area significantly impacting the network needs. Distilleries have indicated

[2] https://www.ssen.co.uk/globalassets/about-us/dso/current-consultations/for-publication/inverness-and-aviemore-132kv-supply-area---strategic-development-plan---february-2026.pdf

that much of this decarbonisation could happen within the next decade. Further details can be found in the Keith SDP[3].

Figure 4-2 - Whisky distilleries in the Keith 132 kV supply area



- **Ports and Maritime Transportation** – SSEN's networks serve a wide range of ports and maritime transportation hubs across both its licence areas. There are many smaller ports in our north of Scotland licence area with many supporting local industries including fishing and offshore wind developments. Others serve as critical transport routes between our Scottish Islands. Many of our inter-island ferries crossings are operated by Caledonian Maritime Assets Ltd (CalMac). CalMac serves many of our island communities particularly across the Hebridean island groups with 35 vessels across 30 routes and 50 ports. CalMac has committed to decarbonising their fleet, electrifying smaller ferries by 2027 and increasing the number of hybrid vessels across all their routes from 3 to 8. Fleet electrification will create potential demand requirements of 1-5 MVA per port. Additionally, the adoption of shore power 'cold ironing' for berthed vessels could contribute up to 8MW of additional demand capacity across the islands. Further south, the Solent Industrial Cluster has identified ports as strategically important with the cluster exploring CO_2 shipping infrastructure and local carbon storage opportunities to support industrial decarbonisation. Maritime transportation is also critical on the Isle of Wight and is a key industry in driving the need for a fourth subsea cable connecting the island to mainland GB.
- **Data and AI Centres** - West London and the associated M4 corridor has been a particular hot spot for data centre development. Data centre capacity is challenging to forecast with initial notifications often at the connection application stage. This challenge is reflected in the SEN process representation. Last year, the Greater London Authority (GLA) published their report into London's Data Centre Future Growth Forecasts & Strategic Insights[4]. This further corroborated West London's strategic importance as a data centre hub with the report noting it had the strongest concentration of data centres in London. The report estimated 324 MW of potential

[3] keith-132kv-supply-area---strategic-development-plan---february-2026.pdf
[4] London's Data Centre Future Growth Forecasts and Strategic Insights | London City Hall

connections to the SSEN distribution network with further connections direct to the local NGET network. The report also noted the potential for further growth given the proximity to existing telecommunications infrastructure and transport links including Heathrow.

Finally, it is also worth noting the work we've undertaken with the Island Centre for Net Zero to understand future demands on Scottish Islands including a range of industries. Further details can be found in our (ED3-S17) Islands Annex.

4.4.7 ISLANDS STRATEGY (ED3-S17)

In ED2, we developed long term strategic plans for Orkney and Hebridean Island groups as part of our proposals for the Hebrides and Orkney Whole System Uncertainty Mechanism (HOWSUM). These strategic plans were developed through a whole system approach considering multiple drivers including decarbonisation of our Diesel Embedded Generation fleet and consequential future network resilience as well as ensuring future network needs were met.

We've taken a similar whole system approach, building on these plans and bringing in the Shetland island group and Isle of Wight, to develop our ED3 submission. The consideration of future network demand and generation has taken a complementary approach to equivalent work on the mainland, utilising the t-RESP. In the case of Scottish Islands though this has been supplemented with local insights gathered by the Island Centre for Net Zero. This is to ensure that the long-term island strategies are suitably sized for future needs, as requested by Ofgem in their response to our HOWSUM 2025 submission. Our detailed Islands investment approach is detailed in the dedicated Islands Annex to our Business Plan.

4.4.8 STAKEHOLDER ENGAGEMENT INFORMED DEVELOPMENT OF OUR PLAN

Stakeholder engagement is a core input to our load forecasting, strategic planning and investment decision-making. We've engaged Local Authorities, developers, major industrial and commercial customers, housing developers, community energy groups, flexibility providers, connection customers, technology providers, consumers and wider energy-system partners. Engagement has taken place through our Distribution Future Energy Scenarios, Strategic Development Plans, connections forums, consultations, research, workshops, roundtables and bilateral discussions. This provides both broad customer and stakeholder insight and more targeted evidence about emerging requirements in particular sectors and locations. The detailed stakeholder groups, engagement routes and resulting impacts on our plan are set out in ***Appendix 3***.

Our ED3 LRE plan has been informed by engagement with over 2,000 stakeholders, at over 50 dedicated events, alongside ongoing engagement through our Distribution Future Energy Scenarios (DFES), Strategic Development Plans (SDPs), connections activities and bilateral discussions. Through engagement with Local Authorities, developers, major customers, community energy groups and wider industry stakeholders, and evidence from Local Area Energy Plans (LAEPs), local development plans and wider regional planning activities, we've strengthened our understanding of the scale, timing, location and certainty of future electricity demand and emerging local requirements. Further detail on our wider ED3 stakeholder engagement is provided in section 2 of our ED3 Business Plan.

The table below summarises the most material stakeholder themes, how they have influenced our LRE plan and the important differences between our two licence areas. It is intentionally a concise synthesis. **Appendix 3** provides the supporting engagement and decision trail.

Table 4-6 - Summarised stakeholder insights and impacts

Stakeholder Theme	Stakeholder Feedback (summarised)	Business Plan Impact (summarised)	Regional considerations
Supporting local economic growth and place-based planning	Stakeholders supported coordinated planning between SSEN, Local Authorities, NESO, government, developers and communities. Local Authorities sought earlier engagement, better planning information and practical support to align network development with housing, transport, economic development and local decarbonisation plans. Community groups also sought clearer routes into network planning and connections processes.	Local planning evidence is used alongside tRESP, DFES, Strategic Energy Needs, contracted connections and network data to identify emerging requirements and improve the location and timing of demand forecasts. Where sufficiently evidenced, it informs network studies and the assessment of reinforcement, flexibility or uncertainty mechanisms.	**North, SHEPD:** stronger focus on rural economies, island requirements, remote communities and emerging demand from distilling, ports, hydrogen and transport. **South, SEPD:** stronger focus on housing and commercial development, industrial decarbonisation, data centres and strategic growth corridors.
Providing capacity and accelerating connections	Stakeholders called for faster and clearer connections, better visibility of headroom, constraints and curtailment, and greater certainty over costs and timescales. Priorities differ by segment: large energy users place greater emphasis on connection speed and certainty, while consumers and community groups also stress affordability, accessibility and fairness.	Connections and stakeholder evidence help test the maturity, scale and certainty of future demand. Higher-confidence requirements are considered for reinforcement, while less certain requirements may be managed through flexibility, monitoring, phased development or uncertainty mechanisms.	**North, SHEPD:** geographic and network constraints can create longer delivery times, increasing the importance of early planning, resilience and security of supply. **South, SEPD:** stakeholders place strong emphasis on reducing connection delays and providing earlier visibility of reinforcement requirements in areas of rapid growth.
Strategic and transparent long-term planning	Stakeholders asked for accurate and granular forecasts, transparent assumptions and understandable explanations of how national, regional and local evidence influences investment. Consumers also emphasised reliability, resilience and long-term value for money.	Engagement has supported the development of more transparent forecasting, strategic network planning and options assessment. Stakeholder evidence complements, but does not replace, the formal evidence required to justify investment. This helps target expenditure towards well-evidenced needs while retaining optionality where future demand remains uncertain.	Both licence areas support closer alignment of national, regional and local planning. Local Authority coordination has been particularly prominent in the South, while whole-system resilience and long-term island planning are particularly important in the North.
Using flexibility to maximise network capacity	Stakeholders supported flexibility as a tool for managing constraints and uncertainty but highlighted complexity, market accessibility, transparency and the ability of smaller providers and communities to participate.	Flexibility is considered through Build and Flex where it can provide an economic, technically viable and deliverable response.	Flexibility markets are more mature in parts of the South. In the North, flexibility remains important, but opportunities can be constrained by network

	They were clear that flexibility should complement, rather than automatically replace, enduring reinforcement.	It may be used to optimise investment, manage uncertainty, accelerate access or support portfolio deliverability, while reinforcement is progressed where enduring capacity is required.	characteristics, geography and available market depth
Coordinating local works and minimising disruption	Consumers, Local Authorities, developers and utilities asked for earlier visibility of local upgrade programmes, clearer communications and better coordination so that works are undertaken efficiently and repeat disruption is minimised.	This has informed the development of coordinated LV programmes, customer communications and engagement with Local Authorities and other utilities. The approach seeks to package related service, feeder and secondary-network interventions where this is efficient and supported by network need.	Coordination is important in both areas. Delivery in remote and island communities may require approaches suited to geography and supply-chain access, while denser parts of the South create greater opportunities and need for coordination with housing, transport and utility works.

How stakeholder evidence informs our planning

Stakeholder evidence helps identify future requirements that may not yet be fully visible through historic network loading, national planning assumptions or contracted connections. This includes housing and commercial development, transport and heat electrification, industrial decarbonisation, data centres, ports, hydrogen developments and community energy projects. It also provides insight into the importance stakeholders place on connection speed, network resilience, planning transparency, affordability, flexibility and the coordination of works.

These insights complement tRESP pathways, Strategic Energy Needs, DFES, contracted connections and network data. Where stakeholder evidence is sufficiently mature and meets the relevant evidence thresholds, it informs forecasts, network studies and optioneering. Where a development remains less certain, the intelligence is retained within our strategic planning process and monitored as the evidence develops. Stakeholder evidence therefore strengthens the evidence base for investment but does not act as an investment trigger in isolation. This distinction helps protect consumers from premature expenditure while allowing emerging needs to be identified early enough for efficient planning and delivery.

Reflecting the different needs of the North and South

Our engagement reflects the different network, geographic and customer characteristics of the two licence areas as in

Table 4-6 above. In the North, stakeholders have placed particular emphasis on rural and island resilience, the electrification of remote economies and the geographic and delivery constraints that can lengthen the time needed to provide capacity. Engagement with Local Authorities, communities, industrial users and

island stakeholders has also provided insight into emerging demand from distilling, ports, hydrogen and transport.

In the South, engagement has highlighted the pace of housing and commercial development, industrial decarbonisation, data-centre growth and other major new loads. Stakeholders have placed particular emphasis on faster connections, earlier visibility of network constraints and closer alignment between Local Authority plans, regional development and network investment. Across both areas, stakeholders expect network development to support economic growth and electrification while maintaining resilience, affordability and long-term value.

Engagement across the network

The engagement informing our LRE plan is not limited to the LV network. It covers customer needs and network requirements across EHV, HV and LV:

- **EHV and primary networks:** engagement with major industrial and commercial customers, developers, Local Authorities, connection customers and energy-system partners helps identify large or step-change demand, test the maturity and location of strategic developments and inform Strategic Development Plans, network studies and optioneering. Examples include industrial decarbonisation, data centres, ports, hydrogen developments, island requirements and strategic growth corridors.
- **HV networks:** connections intelligence, Local Authority plans and developer engagement help identify the combined effect of housing, commercial development and small and medium-sized connections. Because the timing and precise location of this demand can remain uncertain, this evidence supports ongoing forecasting, reinforcement prioritisation and the consideration of flexibility as requirements become clearer.
- **LV and secondary networks:** consumer, Local Authority, housing-developer, community and technology-provider engagement has shaped the approach to service unlooping, secondary transformers, feeder reinforcement, programme visibility, communications and coordination of local works. It has also highlighted the need to consider disruption, vulnerability and community circumstances alongside the technical evidence of network need. Section 6.1 details specific customer research and practical ED2 pilots focused on how LV works should be designed and delivered.

From stakeholder evidence to customer outcomes

Stakeholders have consistently supported investment that enables connections, electrification and economic growth, while emphasising the importance of affordability, resilience and long-term value. These priorities are reflected in how we translate stakeholder evidence into our LRE planning and investment decisions. Stakeholder insight is considered alongside tRESP, Strategic Energy Needs, contracted connections, network data and our forecasting and network studies, helping us understand not only where and when capacity may be required, but the level of confidence we can place in that need.

This evidence supports our Build and Flex approach. Where the need for enduring capacity is sufficiently clear, we can progress reinforcement with greater confidence; where the timing or scale of future demand remains uncertain, we can retain optionality and use flexibility where it provides an efficient and viable response. This helps us provide capacity when customers need it, avoid unnecessary or premature investment, and reduce the risk that delayed intervention becomes a barrier to connections or economic

growth. This balance between readiness and affordability is also at the heart of Ofgem's ED3 Build and Flex approach.

In this way, stakeholder engagement is not a separate input to our strategy, but part of the evidence used to make better-informed investment decisions. It directly supports the three customer outcomes set out in the enabling growth and electrification section, investing with confidence and delivering long-term value.

4.5 LICENCE AREA LOAD PROJECTIONS

The preceding sections describe the planning inputs, DNO-defined building blocks, energy load assumptions and SEN assessments that underpin SSEN's licence area load forecast. These projections represent our current best view of future electricity demand across the SEPD and SHEPD licence areas and form the foundation of our ED3 Load Related Expenditure (LRE) plan.

Figure 4-3 summarises the forecasting framework used to develop the licence area load projections applied throughout this strategy.

Figure 4-3 - Development of SSEN licence area load projections



4.5.1 CURRENT BEST VIEW OF FUTURE DEMAND

We use historic demand as the starting point for our forecasts and combine this with forward-looking planning inputs, including tRESP assumptions, contracted connections, Strategic Energy Needs (SENs) and local and stakeholder evidence. Together, these inputs provide our current best view of how electricity demand is expected to develop across our two licence areas.

Baseline network loading is determined using metered consumption data where available. At lower voltage levels, where half-hourly metering is not available, smart meter data, customer attributes and network topology are used to derive aggregated baseline demand through a bottom-up approach. This provides network-wide coverage while maintaining consistency and traceability in the starting point from which future demand growth is forecast.

Our two licence areas have distinct network and customer characteristics, resulting in differences in both the scale and composition of future demand growth. The following projections therefore present our current best view for SEPD and SHEPD and identify the principal drivers of peak demand growth to 2050.

LCT Uptake

Figure 4-4 and Figure 4-5 compare forecast low-carbon technology (LCT) volumes for 2025/26 across successive DFES iterations with actual connected volumes. EV uptake continues to grow significantly across both licence areas, particularly in SEPD, where it is ahead of the national average. Under the System Transformation (ST) scenario, heat pump projections have reduced slightly in SEPD but increased in SHEPD, reflecting differing regional uptake trends. Slower heat pump uptake nationally reinforces the need for a lagging heat pump sensitivity in ED3 planning, recognising the risk that near-term uptake could fall below net zero-aligned projections. In SHEPD, the higher proportion of off-gas properties compared with the GB average is expected to support stronger heat pump uptake as heat electrification progresses.

Figure 4-4 - Electric vehicles in 2025/26

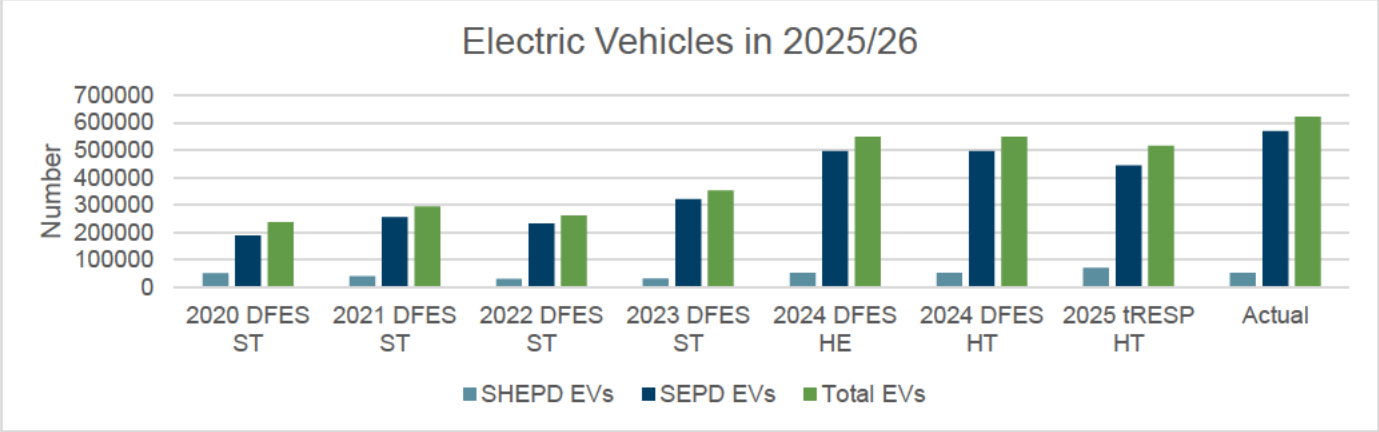
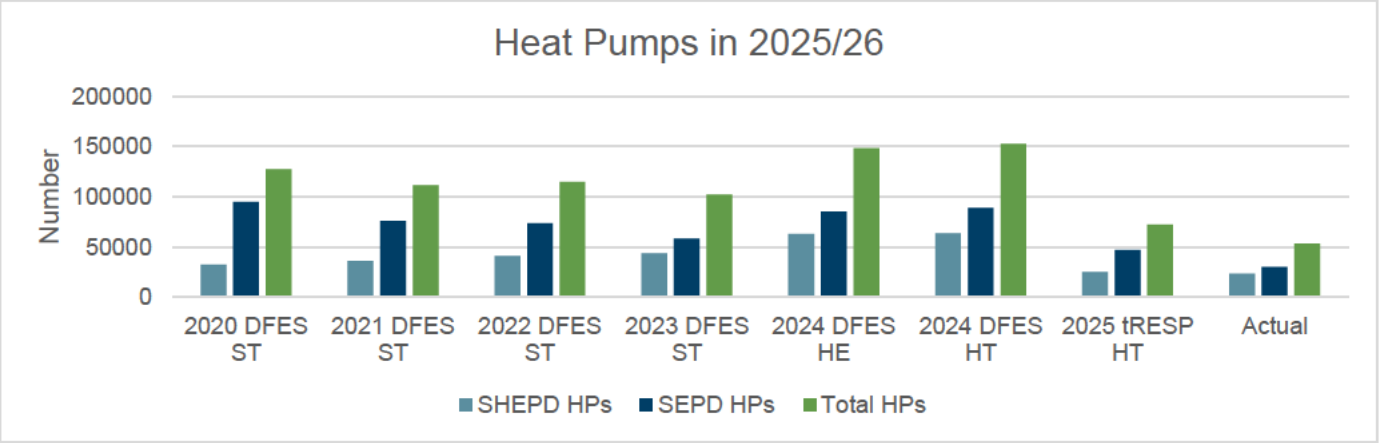


Figure 4-5 - Heat pumps in 2025/26

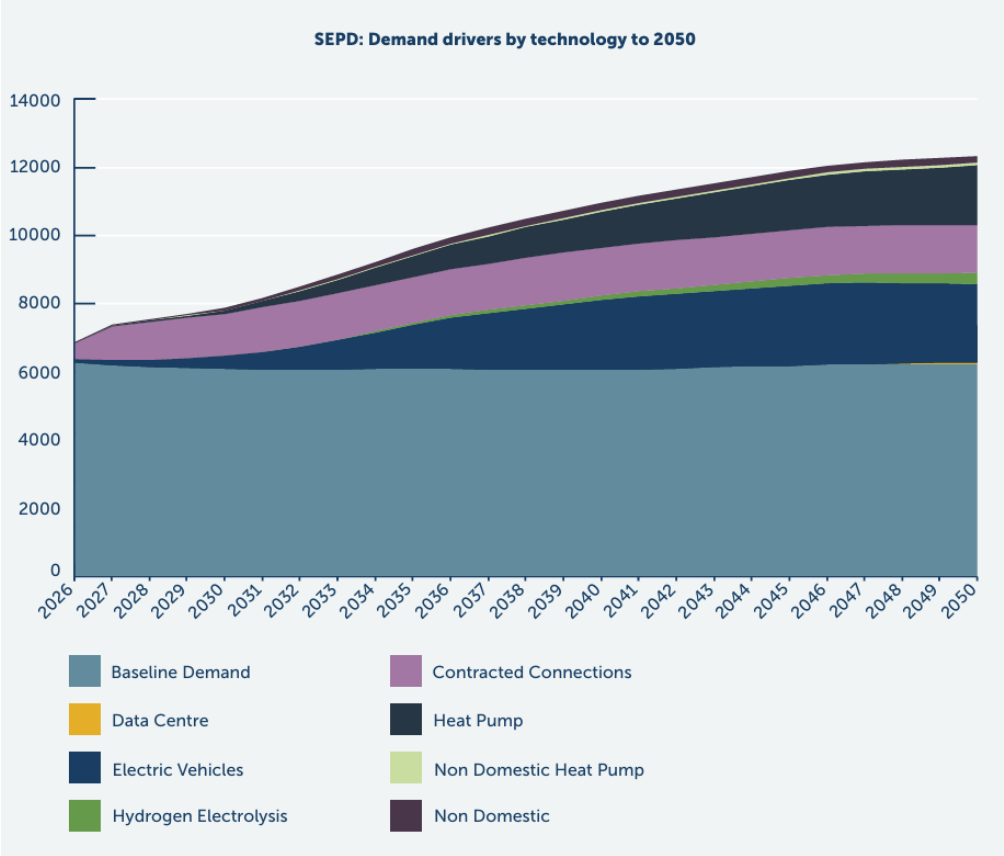


SEPD Licence Area Demand Outlook

Figure 4-6 presents our current forecast of peak demand growth across the SEPD licence area to 2050 and the principal technologies driving that growth.

Peak demand in SEPD is forecast to approximately double by 2050. While baseline demand remains broadly stable throughout the forecast period, significant growth is expected from the electrification of transport and heat, together with wider economic growth, non-domestic demand growth and future customer connections.

Figure 4-6 - SEPD demand drivers by technology

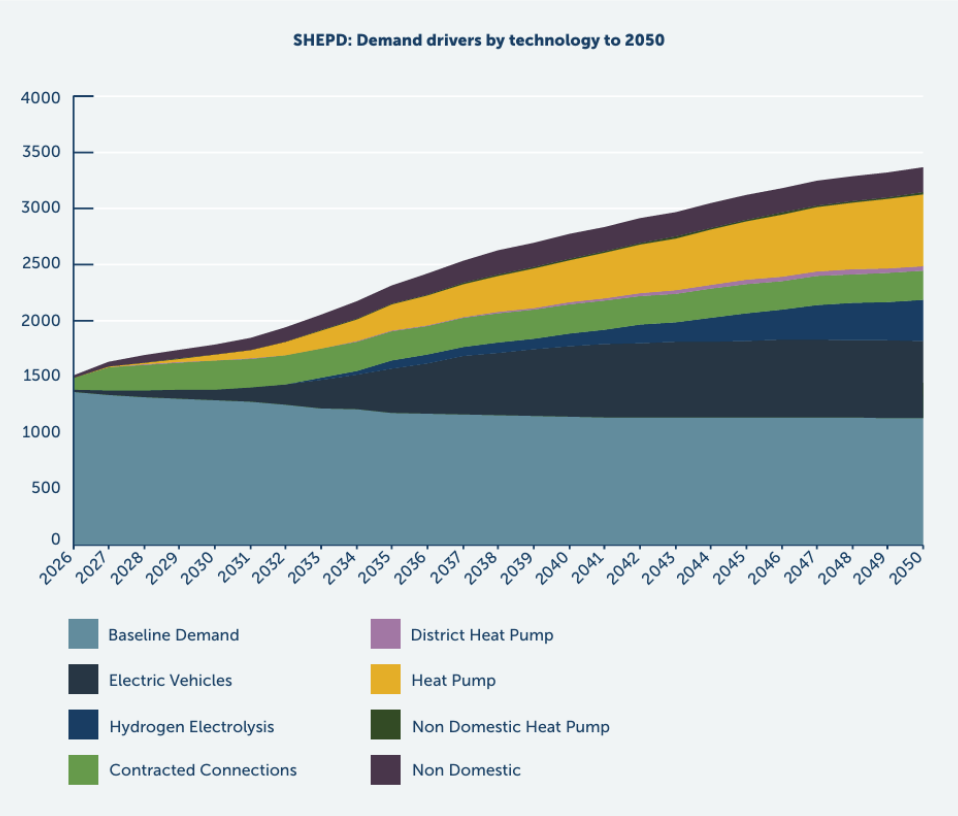


Electric vehicles and heat electrification represent the largest contributors to future demand growth, reflecting the increasing adoption of low-carbon technologies by both domestic and commercial customers. Growth in non-domestic demand and contracted customer connections also contributes materially to future network requirements, reflecting continued economic growth and increasing demand for electricity across the licence area. Emerging demand from technologies such as hydrogen electrolysis and data centres is also forecast to contribute to future requirements, although these represent a smaller proportion of overall demand growth.

SHEPD Licence Area Demand Outlook

Figure 4-7 presents our current forecast of peak demand growth across the SHEPD licence area to 2050 and the principal technologies driving that growth.

Figure 4-7- SHEPD demand drivers by technology to 2050



Peak demand in SHEPD is forecast to increase by approximately 2.5 times by 2050. The principal drivers of demand growth are forecast to be electric vehicles, heat pumps, wider heat electrification, hydrogen-related demand, non-domestic growth and future customer connections. In particular, hydrogen electrolysis is expected to make a more significant contribution to future demand growth in SHEPD than in SEPD, reflecting the strategic opportunities associated with renewable energy resources and the development of a low-carbon hydrogen economy in northern Scotland. Alongside this, continued electrification of heat and transport remains a major driver of future network requirements.

Comparison of Peak Demand Drivers

While the scale of growth differs across the two licence areas, the principal drivers of future demand are broadly consistent. Electrification of heat and transport are expected to be the most significant contributors to increased electricity demand across both SEPD and SHEPD, reflecting the continued transition towards a low-carbon energy system.

There are, however, important regional differences. Demand growth in SEPD is influenced more heavily by wider commercial, industrial and population-related growth, alongside the adoption of low-carbon technologies. In contrast, a greater proportion of future growth in SHEPD is associated with hydrogen-related demand and strategic energy-transition opportunities.

Across both licence areas, future demand growth is expected to arise from a diverse range of technologies and sectors rather than a single source of demand. This reinforces the need for a coordinated approach to network development that combines strategic network reinforcement, operational interventions and flexibility solutions to ensure sufficient capacity is available to support future customer requirements, economic

growth and decarbonisation ambitions.

4.5.2 ACCOUNTING FOR FUTURE UNCERTAINTY

Recognising the uncertainty in long-term forecasts, SSEN has tested the robustness and timing of our investment needs through additional sensitivity analysis.

Heat pump uptake is a key uncertainty. We assessed a DNO-developed sensitivity reducing heat pump uptake in the tRESP pathway by 55%, aligning it more closely with other industry reference points such as the Warm Homes Plan. This helps identify investments that are robust across multiple futures and those better managed through in-period mechanisms. EV projections remain aligned to central tRESP, as uptake is already tracking ahead of forecast.

Uncertainty also remains around the scale and location of small and medium HV and LV connections. While DFES and tRESP inform aggregate demand, flexibility will help manage this uncertainty, accelerate connections and support portfolio deliverability.

Where sensitivities materially reduce ED3 demand growth, we have considered whether investment can be deferred without compromising longer-term readiness. While this can affect the timing of some interventions, it does not generally change the underlying need for network development to 2050. This evidence informs our proposed approach to baseline funding, Build and Flex, uncertainty mechanisms and substitutability, balancing affordability with the need to provide capacity when required.

5. NETWORK PLANNING

This section explains how our licence-area load projections are translated into identifiable network constraints and then into efficient intervention choices. It summarises the network impact assessment across EHV, HV and LV, including the scale, timing, duration and location of forecast constraints, before explaining how reinforcement, flexibility and wider whole-system options are assessed through our optioneering process. Our Build and Flex approach considers economic efficiency, certainty of need and portfolio deliverability so that customers receive capacity when required, network safety and reliability are maintained, and investment is not committed earlier than necessary.

5.1 IDENTIFIED CONSTRAINTS

5.1.1 NETWORK IMPACT ASSESSMENT

Our licence area load projections are translated into network requirements to identify the nature, scale and timing of future constraints across the EHV, HV and LV networks. These constraints provide the evidence base for subsequent optioneering and investment decisions, including consideration of flexibility and network reinforcement.

For clarity, in SEPD (South) our Primary or EHV Network includes 132kV, 66kV and 33kV. In SHEPD (North of Scotland), this network comprises only 33kV, as 132kV is a Transmission voltage throughout the SHEPD licence area.

The network impact assessment provides the critical link between future electricity demand and investment planning. It enables us to understand:

- Where future constraints are expected to emerge;
- The type of network constraint that will arise;
- When network intervention is likely to be required;
- The scale of capacity increases required;
- The most appropriate voltage level for intervention; and

- Whether flexibility is a viable alternative.

The methodology used to identify load-related needs is consistent across both licence areas. Our process combines existing network models similar to those published within our Long-Term Development Statement (LTDS), however also includes contracted connections, associated reinforcement data, and the demand and generation projections from the tRESP pathway out to 2050. This data allows us to implement the pathway within comprehensive load-flow modelling to assess future network security 'non compliances', based on the range of input pathways and sensitivities set out above, for each year of assessment.

Key parameters evaluated

Network impact assessments were undertaken across the EHV, HV and LV networks using our power system models and network planning tools. Forecast demand growth was applied to network models and assessed against relevant planning standards, operational requirements and asset capabilities outlined in Table 5-1 below, to identify emerging constraints relating to future network performance and customer outcomes.

Table 5-1 - Network impact assessment parameters

Parameter	Purpose
Thermal loading	Identify assets exceeding firm capacity ratings
Voltage performance	Assess compliance with statutory voltage limits
Fault level	Assess equipment and switchgear capability
Security of supply	Assess compliance with ER P2 requirements
Network resilience	Assess supply restoration capability under credible outages

These assessments were undertaken at the voltage level most appropriate to the nature of the forecast network need and the potential intervention required.

The outputs of this assessment provide an evidence base for the (ED3-S02) Long-Term Integrated Network Plan (LINP). Constraint analysis and network requirements identified through this process are combined with wider investment drivers, including asset health, climate resilience requirements, Strategic Energy Needs and flexibility opportunities, to develop an integrated view of future network needs.

Assessment approach

Our integrated planning approach ensures that ED3 interventions are considered alongside longer-term network requirements and that opportunities to coordinate investment across multiple drivers and voltage levels are identified wherever possible. It also supports the development of efficient, deliverable and future-ready investment plans that provide value for consumers throughout ED3 and beyond.

This integrated process allows SSEN to move from identifying future load-related network constraints to developing a coordinated programme of reinforcement, flexibility and resilience investments that supports customer needs, economic growth and net zero ambitions.

Using power system analysis software, we've assessed our system out to 2050 using the following:

- **Thermal assessment** – to identify any assets which are at risk of thermal overload due to an increase in demand and/or generation. Thermal overloading can decrease the expected lifetime of an asset; trip system protection leading to customer outages and increase the likelihood of asset failure if overloaded for a prolonged period.
- **Voltage assessment** – to identify any areas of the network which may experience high or low-voltage beyond statutory limits. This can be caused by the increase in demand and/or generation. High voltages can result in damage to equipment, increased losses, and can trip system protection

leading to customer outages. Low voltage can also cause damage to motorised appliances and will increase losses on the system.

- **Fault level assessment** – to identify any areas of the network where the fault level exceeds the rating of the system protection due to the increase in demand and/or generation. If a fault occurs and the fault level exceeds the interrupting current rating of the connected switchgear, this may cause severe damage to assets and more importantly risk the safety of anyone around these assets at the time of fault. This assessment has been run at worst case (maximum demand/maximum generation) and any fault levels identified to be more than the switchgear rating have been considered for reinforcement.
- **Flexibility assessment** - to identify any constraints that can be alleviated by flexibility, with our core planning use cases considering where it can be used to optimise for efficiency, manage uncertainty and support deliverability through wider portfolio optimisation. Flexibility is assessed for both its technical and commercial viability, with the technical assessment ensuring that the use of flexibility does not breach network compliance standards, or compromise network integrity. This must work effectively in a model that also takes account of operational flexibility use cases as described in our (ED3-S10) DSO strategy.

Studies were undertaken across multiple planning horizons extending beyond ED3 to ensure that both near-term and longer-term requirements were considered. This allowed us to identify not only where constraints emerge during ED3, but also where future growth may influence the design and timing of interventions.

Where constraints were identified, further analysis was undertaken to determine the timing of interventions and assess the suitability of reinforcement, flexibility and alternative whole-system solutions. The resulting requirements were taken forward into the optioneering process and relevant EJPs.

5.1.2 SUMMARY OF NETWORK CONSTRAINTS IDENTIFIED

The network impact assessment identified future constraints across primary, secondary and transmission-connected parts of the network. Most identified constraints are associated with thermal loading increases driven by the electrification of heat and transport, growth in distributed energy resources and wider economic development across our licence areas.

Additional constraints were identified relating to fault level exceedances, security of supply requirements and resilience needs, including within island and remote parts of our network, where network characteristics and geographic constraints can increase the importance of maintaining long-term reliability and operational resilience.

Table 5-2 below summarises the types of constraint experienced on the network by voltage level along with typical drivers and a typical response:

Table 5-2 - Summary of future constraints

Constraint Type	Voltage Level	Typical Driver	Typical Response
Thermal Capacity	EHV, HV, LV	Growth in peak demand and electrification	Reinforcement and/or flexibility
Voltage	HV, LV	Rising network utilisation and changing power flows	Reinforcement, voltage control and flexibility
Fault Level	EHV, HV	Network growth and increased system transfers	Fault level mitigation and switchgear upgrades
Security of Supply	EHV, HV	Reduction in network headroom and compliance margins	Reinforcement and network reconfiguration

Resilience	Primarily island and remote networks	Increased exposure to outage events	Reinforcement, automation and resilience investments

The identified constraints form the basis of the intervention portfolio developed through the ED3 planning process and are reflected in the EJPs and investment categories described in Section 1.

5.1.3 NETWORK IMPACT ASSESSMENT OUTPUTS

The network impact assessment provides a forward view of future network utilisation and identifies where and when intervention is expected to be required. These outputs are a first pass review of constraints, and support the development of reinforcement programmes, flexibility requirements and investment phasing decisions. These constraints are part of what is reported in both our Network Development Plans down to Primary level, and Strategic Development Plans at each GSP, both refreshed on an annual basis. Table 5-3 shows the volume by type of network impact assessment outputs for SEPD and SHEPD:

Table 5-3 - Network impact assessments outputs (Full HT Scenario)

Output SEPD	ED3	ED4
Primary substations (EHV/HV) – Thermal and/or Voltage Constraint	35	135
Secondary substations (HV/LV) – Thermal and/or Voltage Constraint	1,604	2,024
Fault level issues identified	52	132
New demand capacity required (MVA)	2,501	4,267
Output SHEPD	ED3	ED4
Primary substations (EHV/HV) – Thermal and/or Voltage Constraint	81	136
Secondary substations (HV/LV) – Thermal and/or Voltage Constraint	2,547	4,512
Fault level issues identified	3	7
New demand capacity required (MVA)	692	1,289

The above outputs are the results of power flow analysis under network intact, and fault scenarios while using the tRESP HT scenario. Our Network Impact Assessment pre-dates Ofgem's decision to weaken the HT scenario using the 45% Heat Pump reduction however we have considered this sensitivity within our optioneering process. Our ex-ante allowances reflect the impact of this weakened scenario, and flexibility assessment.

5.2 OPTIONEERING – BUILD AND FLEX STRATEGY

Our established Distribution Network Options Assessment (DNOA) provides the transparent framework through which we assess credible options to address identified network needs. It considers holistic network options alongside smart and flexibility solutions to identify the most efficient response, with options assessed using the industry-standard Common Evaluation Methodology (CEM) where applicable. The methodology has been developed through stakeholder consultation and is subject to independent assurance, with DNOA outcomes published to provide transparency over our decision-making. Our full DNOA methodology and published outcomes are available on the SSEN Distribution website.

For ED3, our Build and Flex approach builds on this established DNOA process, extending our assessment to explicitly consider certainty of need and portfolio deliverability alongside economic efficiency. This ensures

reinforcement is progressed where enduring capacity is required, while flexibility is used where it can provide a more efficient response, manage uncertainty or support delivery.

5.2.1 TRIGGERS FOR INTERVENTION OPTIONEERING

We begin optioneering when the forecast network constraint enters the practical delivery horizon of the available solutions. This horizon reflects the time required for design, consents, procurement, outage planning, construction and commissioning. Acting too early could commit consumers to unnecessary expenditure, while acting too late could delay connections, reduce resilience or increase delivery costs.

Safe and reliable network operation remains the overriding requirement. We therefore identify interventions before forecast loading creates sustained operation beyond asset capability. At primary-network level, requirements are identified through network studies assessing thermal loading, voltage, fault level, security and resilience across relevant scenarios. At secondary-network level, intervention is generally triggered when forecast demand indicates that an asset will exceed the ratings set through applicable asset policy and standards.

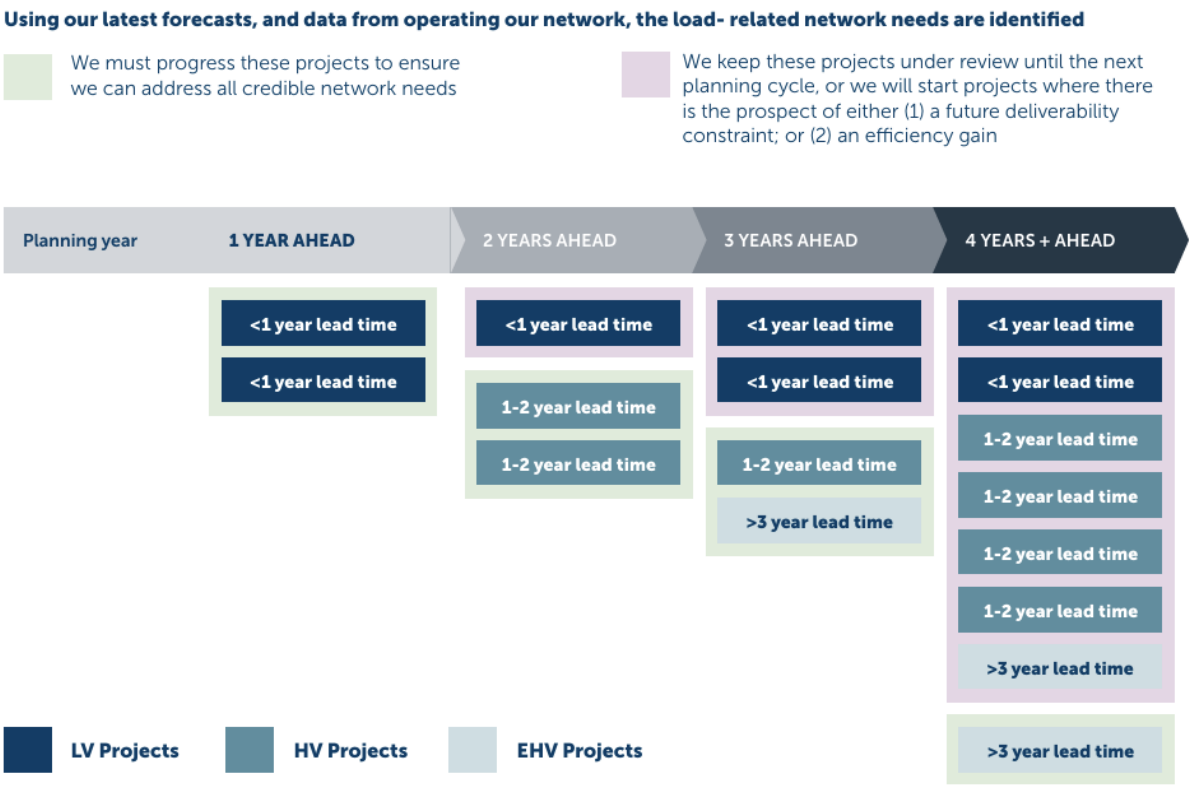
Where the timing or scale of need remains uncertain, we monitor the requirement and use flexibility where it provides a technically viable and efficient means of maintaining capacity and optionality. However, this cannot compromise timely delivery. We retain a credible portfolio of reinforcement projects and consider supply-chain capacity, outage availability and opportunities to package or sequence schemes efficiently.

The preferred intervention and its timing are therefore determined by:

- The certainty, scale and persistence of the network need;
- Safety, security and resilience requirements;
- The lead time and deliverability of available solutions;
- The technical and commercial viability of flexibility; and
- The whole-life value of flexibility compared with reinforcement.

These criteria allow us to progress reinforcement where enduring capacity is required, while retaining flexibility where this can manage uncertainty or improve value for consumers. This supports earlier access to capacity, more confident investment decisions, better network performance and lower long-term whole-system costs. Figure 5-1 below shows a simplified view of planning time horizons versus intervention lead times that trigger intervention thresholds across voltages:

Figure 5-1 - simplified view of planning time horizons versus intervention lead times that trigger intervention thresholds across voltages



5.2.2 BUILD AND FLEX

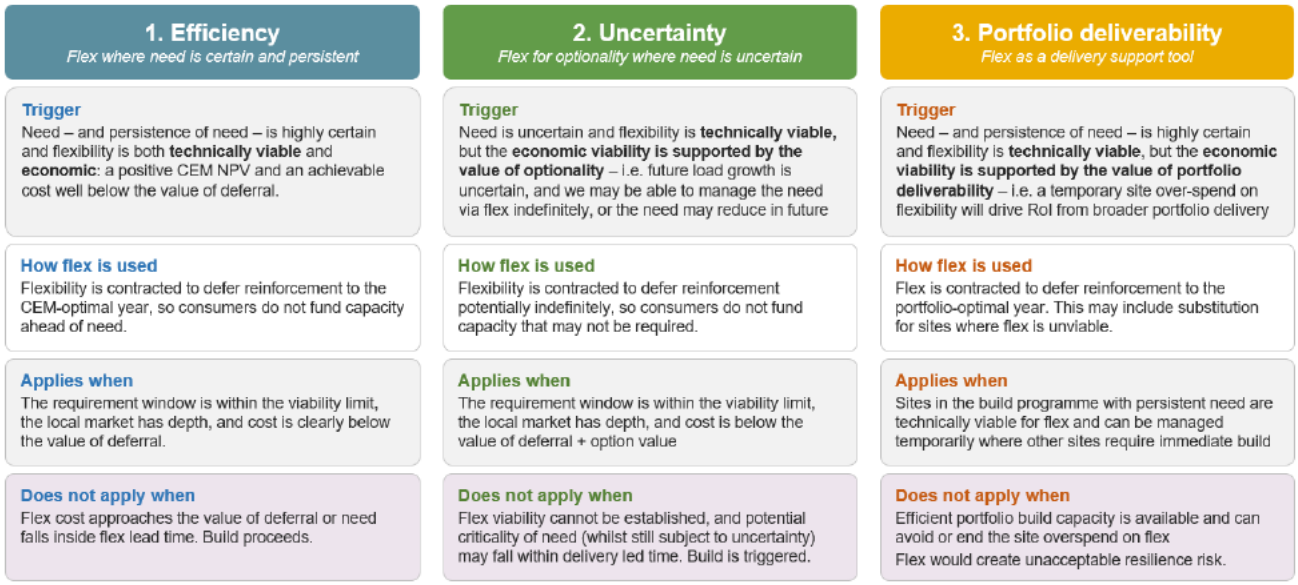
Build and Flex is the framework through which we decide, for every identified network need, whether reinforcement, flexibility services or a combination of the two will best serve consumers. It gives us a consistent, evidence-based way to meet network needs efficiently, manage uncertainty and keep the overall programme deliverable.

In ED3, we push flexibility as far as we can. Individual EJPs set out the flexibility proven efficient and viable at scheme level. Our portfolio goes further and it is built on the maximum-flexibility position, including flexibility to manage uncertainty and secure deliverability. This delivers the lowest-build baseline consistent with maximising flexibility and responds directly to Ofgem's ask that we maximise the use of flexibility.

Flexibility, however, cannot be guaranteed. The flexibility market is developing through ED2 and will continue to scale in ED3, and the volume, liquidity and price available to us will only become fully clear closer to the point of need. We have therefore designed our approach to keep options open. Schemes remain substitutable between build and flexibility, decisions are taken as close to need as lead times allow, and an agile contingency pot allows us to choose the right solution as circumstances change. This allows us to pursue flexibility ambitiously while remaining committed to delivering capacity at the right time and in the right place.

We apply flexibility for three distinct purposes. Each has its own trigger, its own way of using flexibility and its own limits, summarised in Figure 5-2 and explained in the sections that follow.

Figure 5-2 - Use cases for flexibility



Scale of flexibility in ED3

We expect to use flexibility at scale across ED3, with the volume under contract growing through the period as markets mature. Table 5-4 sets out, at each voltage level, the flexibility we expect to require across use cases in ED3. During ED2, we procured flexibility primarily as an alternative to reinforcement, the size of our overall load related expenditure portfolio alongside the new use cases for flexibility in managing uncertainty and deliverability represents a 309% increase in flexibility requirements when compared to our initial ED2 assessments.

Table 5-4 - Flexibility use cases

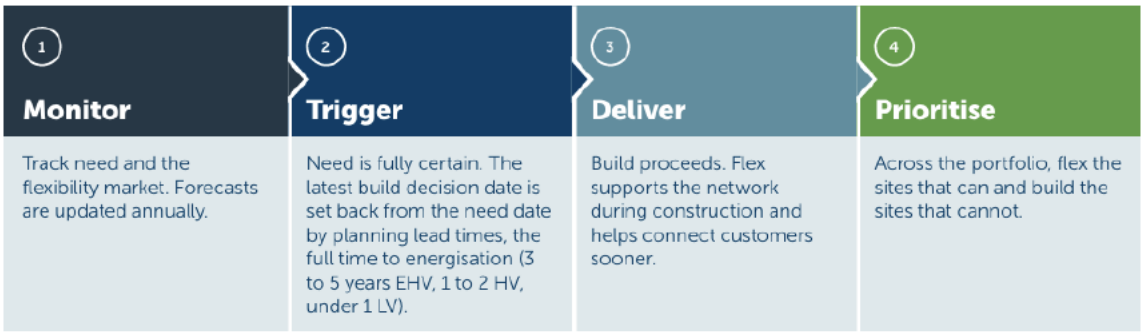
Flexibility Use Case	What it does	Voltage	Capacity (MW)	(£m)	Consumer / Business Value
Alternative to reinforcement	Defers or avoids traditional network upgrades where flexibility is lower cost	EHV	119	[redacted]	Lower bills, reduced network spend, faster deployment than reinforcement
		HV/LV	25	[redacted]	
Manage uncertainty	Provides temporary capacity while future demand and generation requirements become clearer	EHV	1.8	[redacted]	Avoids premature investment and stranded assets
		HV/LV	0	[redacted]	
Optimise investment portfolio delivery	Reprofiles schemes where flexibility provides an interim solution	EHV	115	[redacted]	More affordable and deliverable investment programme
		HV/LV	0	[redacted]	

Ensuring our plan is deliverable

We trigger interventions by working back from the date capacity is required. For each need, the planning lead time for the build solution (design, plant ordering and construction through to energisation) sets the latest date by which a decision must be taken, with planning lead times of 5 to 7 years at EHV, 1 to 2 years at HV and under 1 year at LV. Until then we continue to monitor need and the flexibility market and update our forecasts through our annual forecasting process, so that we commit to an intervention only when need is fully certain. This avoids committing to build before the evidence supports it, while ensuring that delivery can proceed without delay once a trigger date is reached. Even then, flexibility remains valuable: it can

support the network while we build, accelerate connections and help us prioritise the overall portfolio using substitutability.

Figure 5-3 - Timing triggers



Where we will not rely on flexibility

Flexibility is not always in consumers' interests, and we will not rely on it in the circumstances below (Table 5-5). We will support these tests with worked examples from our scheme-level papers showing where flexibility is, and is not, recommended.

Table 5-5 - Barriers to flexibility

Circumstance	How it is tested	Outcome
Requirement window too long	The viability tool compares the length of the exceedance window with the viability limit: under 6 hours for secondary transformers and typically 7 continuous hours elsewhere.	Flexibility is not technically viable. We build, triggered by planning lead times.
Insufficient market depth	We assess the number of customers downstream (e.g. >10 at LV) and regional liquidity, using registered flex assets, the Centralised Network View, the Embedded Capacity Register and SLC31e reports.	We do not rely on flexibility today. We keep the scheme open, develop the market and retest annually; build proceeds if viability is not established by the planning trigger.
Resilience or security of supply risk	A technical assessment considers, for example, P2/6 compliance, asset health, the reliability of the regional flexibility market, and fault rates on existing assets and circuits HV circuits where additional loading would impact network resilience.	Flexibility is not technically viable. We build, even where flexibility would be cheaper.
Flex cost outweighs deferral, option value and deliverability benefit	The CEM assessment value of deferral is compared with benchmarked flexibility costs: previously accepted bids, historic SEPD and SHEPD costs and other networks.	Where need is certain, the site is discounted for flexibility, unless substitution at portfolio level justifies it under use case 3.
Need certain and imminent	We compare the time to need with planning lead times for the build solution.	Build proceeds at pace. Flexibility supports the network and customer connections in the meantime.

Our Build & Flex approach

Stage 1 – Understanding where flexibility is an efficient solution

Building on the capabilities we've established in ED2, our intent for ED3 is to scale flexibility. The optionality stage of our assessment considers flexibility wherever it could reasonably optimise or avoid investment informed by market depth and delivery confidence. For each identified network requirement, we assess whether flexibility is a suitable alternative, whether it is cost-effective and whether it can be delivered with sufficient confidence. We'll then contract for it, and we expect the volume we hold under contract to grow through the period as our markets continue to mature.

Our assessment process considers both the technical viability of flexibility as a solution and also the economic case for flexibility. Together this forms both a transparent and standardised approach to considering efficient use of flexibility while also providing insights to inform both uncertainty and deliverability use cases.

Step 1: Technical viability. Flexibility is technically viable where the requirement window can be met within a given day, the local market has the depth to sustain it, and flexibility does not undermine network resilience. Our viability tool builds on our ED2 experience. It uses DFES projections of demand growth, new technologies and their flexible capability, together with the proportion of new load that is flexible, its diversified contribution to peak and the viable window length (typically 7 hours, varying by location and voltage). It also tests whether enough flexible capacity is available to meet the peak exceedance, and how close available flexibility comes where it falls short. Sensitivity analysis shows the point at which flexibility would become viable, so that we do not foreclose market opportunities.

Step 2: Economic viability. Where flexibility is technically viable, we apply two economic assessments. The first is the industry-agreed Common Evaluation Methodology (CEM), which combines reinforcement cost and timing with the required flexibility volumes and costs, assessing the net benefits of deferral optionality and deliverability against broader measures of customer impact (CI/CMLs) and Losses. The second is benchmarking. We calibrate our flexibility availability and utilisation costs against previously accepted bids and across other networks, including historic SEPD and SHEPD costs and wider DNO market rates, as an indication of provider acceptability. A significant variance between the benchmarked price and the value of deferral may deem flexibility unviable. Where we are confident that flexibility can be secured when accounting for deferral, uncertainty and deliverability benefit, the site is deemed economic.

Stage 2 - Managing uncertainty and deliverability

Our Load Related Expenditure strategy recognises that flexibility is an important lever in managing uncertain need for investment. Under this use case, we review all projects for which flexibility is a viable solution but not economic to understand the certainty of need. At EHV this means either whether the constraint materialises across multiple scenarios including the t-RESP heat pump sensitivity and/or a single contracted connection, while at the lower voltages, exceedance is modelled against the level of overload (i.e. minor overloads are less inherently certain and heavily influenced by the aggregate volume and location of smaller connections). In such cases, we will extend the use of flexibility from the traditional efficiency use case and defer project development until the needs case becomes certain.

We also see flexibility as a key tool to enable us to manage the deliverability of our overall investment portfolio. This includes the use of flexibility to accelerate capacity and enable faster connections, while taking a holistic view of deliverability to ensure we're building a credible and manageable set of needs for supply chain partners. Deliverability works at portfolio level. Where one site is viable for flexibility and another is not, we use substitution: we build the site where flexibility is unavailable and flex the site where it can be used, assessing the cost of the combined plan so that a site can be flexed where this releases delivery capacity elsewhere. Where the need to build is certain, and we are progressing with delivery,

flexibility acts as a delivery support tool, helping us to accelerate customer connections and manage constraints while construction progresses. We see this use case to be primarily following further project development and therefore more relevant for within the ED3 period.

We have used our initial technical and economic assessments to identify projects which may be suitable for uncertainty and deliverability use cases. This approach is summarised in Figure 5-4 below where we can broaden our consideration of viability and deliverability benefits. For example, where flexibility is not yet viable, because the local market lacks sufficient liquidity or because the economic evaluation does not yet support it, we do not rule it out. We keep these projects under review, retesting as the market develops, so that we do not foreclose an opportunity that could emerge later in the period. Build is triggered only when planning lead times require it.

Figure 5-4 - Timing triggers

	Efficiency Need certain and persistent	**Uncertainty** Need uncertain	**Deliverability** Substitution and delivery support
Technically viable Economically viable	**Flex:** Viable and economic.	**Flex:** Viable and economic.	**Flex:** Flex this site by substitution, releasing build capacity for a site that cannot flex.
Technically viable Not economic	**Build:** need certain and flex is not economic.	**Keep under review:** economics not yet proven. Retest as costs and the market develop.	**Flex:** Where the additional value of portfolio delivery efficiency outweighs the inefficiency of flex at a site level
Not technically viable Economically viable	**Keep under review:** retest as the market develops; build when lead times require.	**Keep under review:** liquidity not yet sufficient. Retest as the market matures and the need uncertainty evolves	**Build:** no flex available, prioritised so a flexible site can defer.
Not technically viable Not economic	**Build:** when planning lead times require.	**Keep under review:** keep the scheme open; build only when the need fully materialises and lead times require.	**Build:** no flex available, prioritised so a flexible site can defer.

Flex **Keep under review (flex held up)** **Build**

These additional opportunities can enable us to use flex to deliver capacity more efficiently within the price control period. Below we present examples of where additional flex might be used.

- Project remains uncertain at key decision point.
- Forecast demand rising quicker than expected. Use flex to create capacity.
- New work comes into the plan. Defer other work with agile pot.
- Increased supply chain costs in a particular year may mean that flex becomes an efficient solution

Maximising flex & protecting against uncertainty

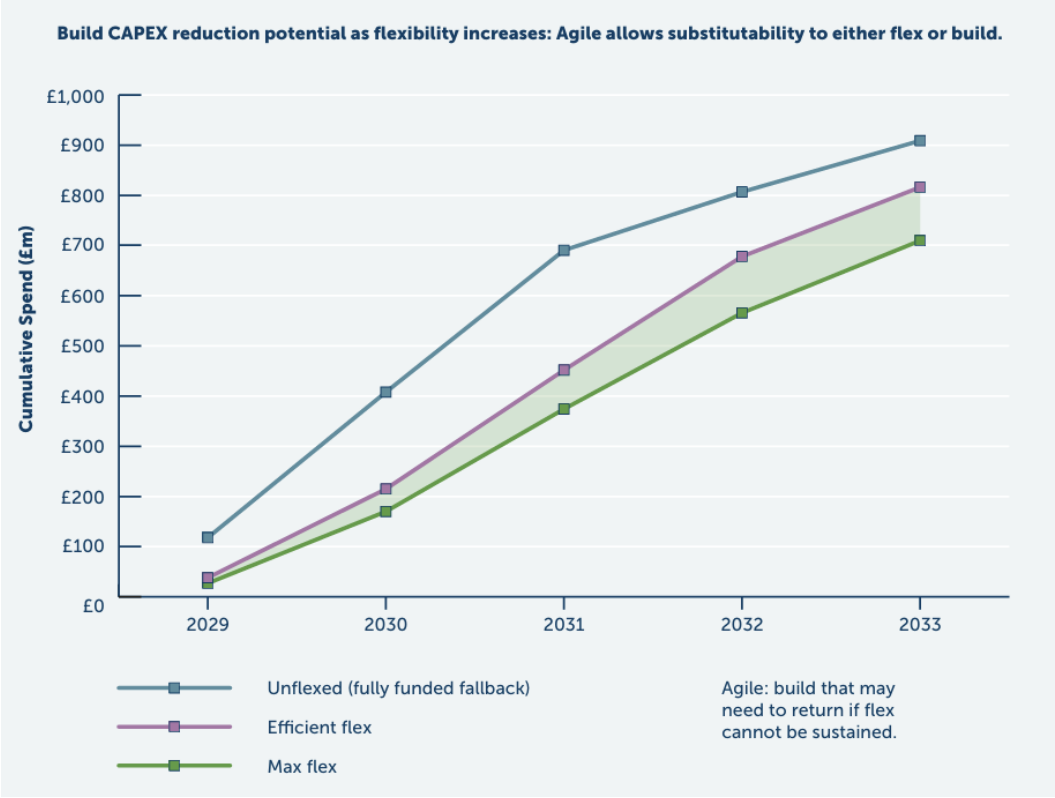
Following the assessment that identified additional flex opportunities, our baseline is set at the maximum flexibility position we can currently identify (green in Figure 5-5), which corresponds to the lowest build CAPEX, because more flexibility defers more build.

Where network needs cannot be met within the initial ex-ante funding and output envelope, we propose a £195m Agile Contingency Pot alongside our baseline ex-ante allowances to manage the risk of flexibility being unavailable to alleviate network constraints and allows us to pivot quickly to a conventional build

solution providing the need remains justified (red line in Figure 5-5). We would draw on the Agile Contingency for three reasons:

- Greater certainty emerges about investment requirements and timing, confirming that delivery is needed in ED3. This includes new needs arising from underlying connections, and boundary or upstream network interventions and constraints.
- Additional flexibility is required to new ED3 projects otherwise due for delivery in ED4 or ED5.
- A build solution is required because flexibility is no longer efficient or economic, including where the flexibility we are relying on does not materialise.

Figure 5-5 - Baseline and agile positions



The Agile Contingency Pot would be pre-approved, with DNOs able to draw on it before an efficiency assessment at the end of the price-control period. This enables us to balance the deliverability of our overall investment portfolio with the flex required, to drive overall efficiency throughout the period. Operating within the proposed LIRM output, it would fund build solutions where required, accelerating delivery and reducing regulatory burden. This supports the substitutability required as it is driven by the delivered LI risk reduction, meaning schemes can be swapped between build and flexibility according to their deliverability and to flexibility viability within ED3. This is supported by DSO investments of over £35m in our strategic network planning, flex toolkit and system orchestration capabilities as detailed in our (ED3-S10) DSO strategy, that enable a smart, dynamic system that meets customer and network needs.

Further information on our initial proposals for the design of the LIRM mechanism and the Agile Contingency Pot is set out in section 7 of this strategy.

6. ENABLING LOCAL NETWORKS FOR LCTS

This section sets out our long-term, programmatic approach to preparing local networks for the growth of electric vehicles, heat pumps, solar generation and other low-carbon technologies. It explains how

secondary-transformer, LV-circuit and service-unlooping needs will be identified and prioritised, how ED2 pilots and innovation inform delivery, and how investment will be coordinated with Local Authorities, communities and other utilities. By combining network readiness, flexibility and coordinated area-based delivery, the approach aims to enable customers to adopt low-carbon technologies sooner, reduce repeat works and disruption, improve local resilience and deliver lower whole-life costs.

6.1 THE CONTEXT FOR LOCAL NETWORK UPGRADES

In January 2026, DESNZ published the Warm Homes Plan[5] setting out a clear national ambition to reduce consumer bills and upgrade British homes through a £15 billion funding package. This will be delivered across several programmes including financial support for installation of Low Carbon Technologies (LCTs) such as domestic heat pumps and solar energy across GB. These smart devices enable bill reductions through access to lower energy prices and participation in flexibility markets. The success of this plan depends on whether local electricity networks can connect LCTs at the pace and scale required.

Reinforcement of our lower voltage network is a key enabler for consumers to access these opportunities and take control of their energy bills. LCTs will trigger growth in local electrification, which has the potential to significantly increase demand on local networks, and a proactive approach necessary to ensure our network is connection-ready.

LCT growth is also closely linked to voltage and fault performance on our Local networks. Our analysis shows that 32% of the highest impacting LV faults occur where the HV/LV transformer is also overloaded, and that 9/10 instances of LCT trips are due to over-voltage. Measures to address LCT growth must therefore be designed to address voltage and fault performance at the same time.

This requires transformational change in our approach to LV network upgrades, which was previously predominantly reactive. It requires DNOs to scale up delivery of proactive unlooping and low-voltage upgrades to create efficiencies, minimising delivery costs and customer disruption while ensuring customers have access to capacity in the right place, at the right time.

This will be the start of a long-term holistic programme of work, through ED3 we'll be growing our capability to deliver around 40,000 LCT enabled homes through a fourfold increase in LV looped services upgrades, while a further 130,000 homes will be enabled through broader low-voltage circuit and secondary transformer upgrades.

We'll also align Local network upgrades with our enhanced coordination role in LCT and Energy Efficiency (EE) rollout in ED3. This section should be read in conjunction with the DNO Role in Low Carbon Technology and Energy Efficiency Rollout annex, which sets out our enhanced coordination role in accelerating LCT and energy efficiency deployment and the complementary activities that will help maximise the value of proactive LV network investment. For example, greater data sharing with Local Authorities and other utilities can enable the development of co-ordinated plans which minimise disruption for communities, and the potential for LCTs to provide flexibility services, under longer term contracts as a means to help support the upfront cost of new installs. Our innovation project, RESOP, has enabled all our Local Authorities with the LAEP+ (LENZA) tool which can facilitate this capability.

As part of our broader market development activities, we'll use implicit pricing products such as our 'Smart Signal' product to manage local constraints on the LV network and support the deliverability of our programme. We're also scaling up our 'Systems for Flex' capability to enable large-scale flexibility tenders, as set out in our (ED3-S10) DSO Strategy. Through pilots, we'll explore smart solutions to creating and managing capacity such as 'virtual unlooping' which would see capacity enabled for LCT use through a combination of solar and battery storage for certain property types. This builds on the groundwork

[5] Warm Homes Plan

developed through our Equal LCT innovation project which showed how different sizes of LCTs can result in different needs and therefore solutions for service unlooping.

6.2 OUR LONG-TERM MULTI-PRICE CONTROL APPROACH

In ED2 our approach to secondary transformer and LV mains upgrades has been predominantly reactive, responding to immediate load related, asset health and new connection needs. Service unlooping has similarly been carried out only when requested by customers, which is time consuming and complex and has made it challenging to meet ED2 unit rates.

The pace of electrification now requires a proactive, programmatic approach. Customers have told us through our ED3 stakeholder events that our LV networks must be ready to connect LCTs (EVs, heat pumps and rooftop solar) when they want them, within two days, and that interactions with us must be simple even where the systems and processes behind them are complex. Where technically feasible and there is a demonstrable value case, we'll use smart network solutions through Build and Flex to keep costs down for consumers, but this must be paired with optimised asset reinforcement ahead of need to accommodate a two to threefold increase in electricity consumption.

Our collaborative DNO research through the Energy Networks Association (ENA) supports this shift. Awareness of service unlooping is currently low, with only 8% of customers having heard of it before taking part, yet both reactive and proactive approaches achieved majority support, and 43% of respondents said proactive unlooping would make them more likely to adopt LCTs, compared with 6% who said less likely. The research also found a gap between expected and actual disruption: customers who had been unlooped reported high satisfaction, fewer than 5% reported an uncooperative neighbour and only 7% experienced significant neighbour disruption. Acceptance is therefore achievable where communications are clear, transparent and delivered through trusted sources, which is why we treat the customer journey as an integral part of the LV programme rather than a communications activity around an engineering intervention.

The LV upgrades in our ED3 plan will increase capacity across the network and enable 40,000 homes on looped services to install LCTs. This is the first stage of a multi-price control programme that will continue to 2050. ED3 is a period of capability development: we'll take learnings from our ED2 pilots to grow internal resource, skills and our supply chain, reaching full delivery capacity by mid-ED3 and sustaining it through the 2030s to avoid future bottlenecks.

Our programmatic approach will focus upgrades on geographic areas where there are intervention drivers across multiple asset classes (secondary transformers, LV circuits and looped services) and prioritised based on broader network needs. This work will be coordinated into single deliverable packages so that we do not need to revisit the same local areas multiple times, and we'll work collaboratively with local communities and Local Authorities in the planning and delivery of this work to minimise any disruption.

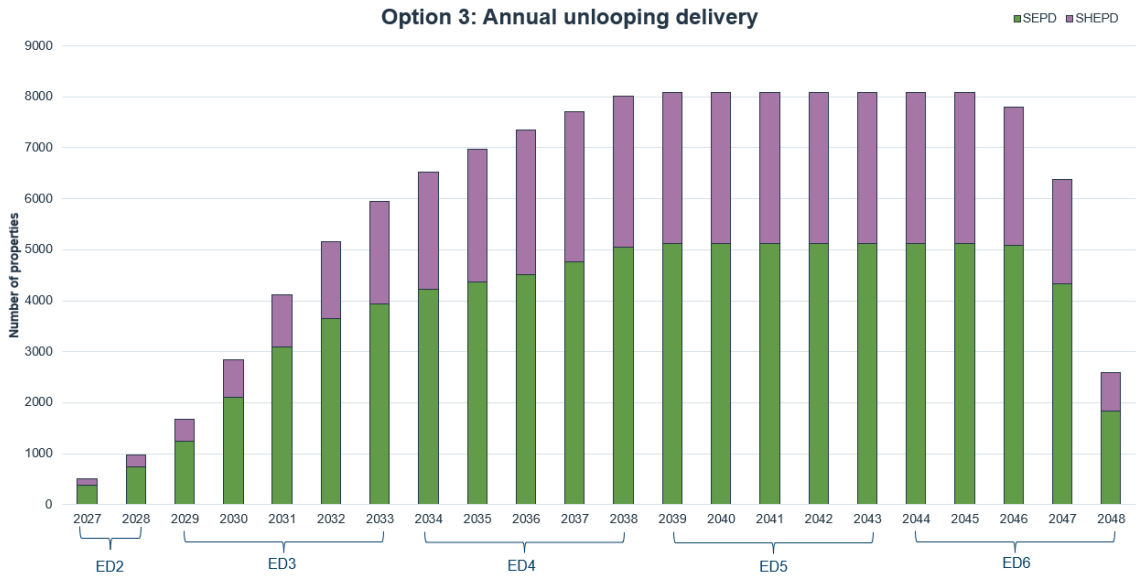
We intend to make a positive impact for communities both through improving areas of our network with known resilience needs and providing access to the Powering Communities Fund for communities affected by our works[6].

6.2.1 ILLUSTRATIVE LONG-TERM TRAJECTORY: SERVICE UNLOOPING

Figure 6-1 illustrates how our LV programme extends across multiple price controls, using service unlooping as an illustrative example. A similar multi-price control profile applies to our secondary transformer and LV circuit programmes.

Figure 6-1- Illustrative service unlooping volumes by year

[6] Further details on this approach can be found in our ***(ED3-S06) Vulnerability Strategy***.



- Remainder of ED2 – pilot delivery to build our knowledge base and mobilise contractor partners, reinforcing 1,482 LV services (1,130 in SEPD and 352 in SHEPD).
- ED3 – a ramped increase in delivery throughout the price control to increase the rate of service unlooping, reinforcing 19,741 LV services (14,029 in SEPD and 5,712 in SHEPD).
- ED4 and beyond – continued ramping of delivery until peak capability is achieved in 2040, maintained through to 2045, then reducing until all identified looped services have been removed from the network.

Having a time-bound commitment to complete this work gives us and our supply chain a deliverable ambition. It meets Ofgem's requirement to establish a forward-looking programme of LV service unlooping and supports wider government policy on the electrification of domestic heating and transport.

6.2.2 DSO AS AN ENABLER FOR OUR LV STRATEGY

Through our stakeholder engagement we've identified several enabling activities needed to deliver programmatic LV upgrades. These will be delivered through our (ED3-S10) DSO strategy, with further detail in the (ED3-S10) DSO and (ED3-S11) DNO Role in Low Carbon Technology and Energy Efficiency Rollout strategy annexes:

- Enhanced forecasting and analytical capability for our secondary networks to support robust long-term programmes.
- Greater sharing of our plans and programmes with Local Authorities and other key stakeholders, to align with other work programmes affecting communities.
- Support for customers on LCTs and how they can be used to manage bills, including clearer information on why network upgrades may be needed.
- Development of LV flexibility services such as Smart Signal to improve management of local network constraints and support prioritisation of delivery across investment drivers.
- Collaboration with local stakeholders to develop plans that work for communities. This will include co-ordination with other utilities to minimise the disruption of our works.

6.3 DESIGNING BY DOING

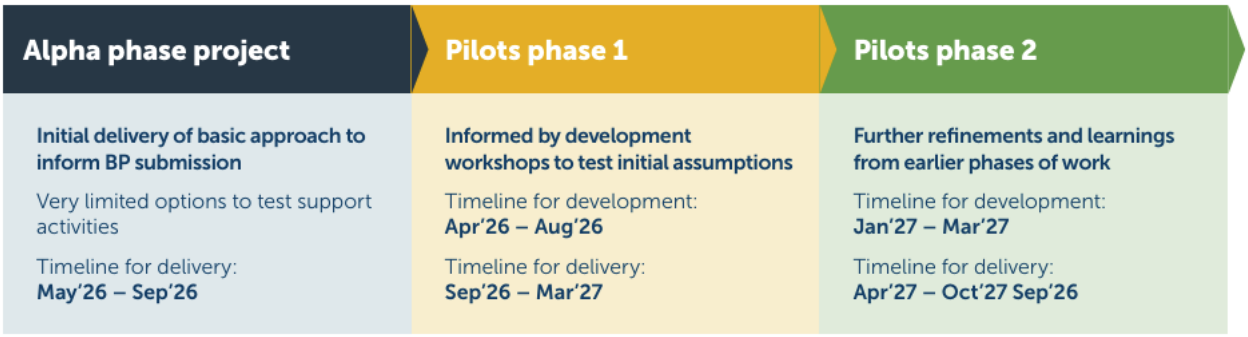
We're piloting proactive, programmatic LV upgrades in our SEPD licence area during the final two years of ED2, following a 'design by doing' ethos. Our pilot approach has been informed by our Independent Stakeholder Group (ISG), and the pilots are developed with key stakeholders, including supply chain partners, and consider the full customer journey from outline work planning and communication through to

delivery. Our Engagement Assurance Report identified the combination of customer research and an active pilot as a strong foundation for our proposed approach. The pilots are testing:

- Optimised programme scope (asset scope, use of three phase, overlay proportions)
- Drivers of differences in unit cost between urban and rural networks
- Resource requirements and skills
- Work delivery options such as zonal delivery
- Engagement requirements with Local Authorities, communities and consumers
- The use of flexibility to alleviate local constraints and support deliverability

The pilots are structured in three phases, each building on the learning from the last as detailed in the diagram below:

Figure 6-2 - Pilot approach: design by doing



The Alpha phase (delivery May 2026 – September 2026) explored the initial delivery of a basic approach to inform our Business Plan submission with over 1,200 surveys completed. The regions selected for this phase intentionally isolated regions with looped services through our LCT Connections Readiness Indicator records validated against Digital Service Card records and, where possible, we targeted properties with meter boxes visibly located on external walls to accelerate early outcomes. We avoided areas co-located with ED2 load related reinforcement or potential ED3 load related reinforcement, and areas where the LV main is likely to be due for asset replacement (CONSAC mains or a high fault count) or has recently been upgraded (WAVECON 300 mains).

Phase one, underway at the time of this submission, will look to test the benefits and synergies of aligning service unlooping with other works on our secondary networks with several thousand further surveys and nearly 500 unlooping jobs to be completed. Phase two will then apply further refinements and learning from earlier phases, extending the scope to flexibility opportunities and LCT enablement, including our proposed 'virtual unlooping'.

We'll broaden the geographies covered in phases one and two, and the pilots will feed directly into the development of the LV standards and policies to be used in ED3.

Robust pilots will allow us to transition smoothly into business-as-usual delivery from the start of ED3, although we'll continue to grow delivery capability, internal resource and our supply chain through the first half of the price control, alongside new skills in areas such as consumer engagement and communications.

6.3.1 LOCAL AUTHORITY ADVISORY BOARD

We've established a Local Authority Advisory Board (LAAB) of Local Authorities across both our licence areas. The LAAB gives us a structured forum to consult a key stakeholder group and has informed both our pilots and our ED3 approach. For example, we shared a draft service unlooping customer journey map with the LAAB at a dedicated workshop, and its insights have helped shape our process for proactive unlooping. Customer journey development is also identifying practical issues to test through the pilots, including management of neighbours, landlords and housing associations, predictable scheduling and the quality of

reinstatement. Early visibility is a particular priority: 85% of respondents to a recent webinar believed their organisation would benefit from early visibility of future works.

To support this, we're also establishing dedicated community liaison teams (4 FTE) to engage stakeholders and support the end-to-end customer journey, alongside customer engagement material including a knowledge library, our Connections Readiness Indicator and an explanation of the customer journey.

6.3.2 INNOVATION UNDERPINNING OUR APPROACH

Innovation through ED1 and ED2 has built the capabilities we need to move from reactive reinforcement to a proactive, coordinated approach, improving our understanding of future demand, local energy planning, customer readiness, flexibility markets and network visibility. Key projects include:

- **LCT Connections Readiness Indicator (CRI)** – provides a robust modelling approach for identifying looped services and is a key input to our ED3 plan.
- **RESOP (LENZA)** – developed with Advanced Infrastructure using its LAEP+ platform, LENZA now has over 400 users and is helping Local Authorities across our licence areas develop their future energy plans.
- **Project LEO and Community Smart Access** – developing local smart markets and, with the Local Energy Market Alliance (LEMA), accelerating the connection of new housing developments.
- **Pathways to 2050** – will inform the direction of our LV strategy as we move into ED3, providing a template for our programmatic approach to LV networks.
- **Equal LCT** - showed how different sizes of LCTs can result in different needs and therefore solutions for service unlooping.
- **The DigiLoop project** - aims to reduce delays in confirming if properties are looped, and if unlooping is requested to make it a smoother engagement experience for customers.
- **Grounds for Change** - will validate a Toolbox of low-impact LV cable installation methods to cut service upgrades from multi-day trenching to same-day works, minimising consumer disruption.

During ED3 these capabilities will be embedded into core planning processes, supporting more efficient investment decisions, proactive network readiness and improved coordination with customers, Local Authorities and regional stakeholders.

6.4 OUR PRIORITISATION APPROACH

We're conscious of the impacts of our work on consumer energy bills and have developed a robust prioritisation process that will enable us to focus on areas of our network with clear and immediate load related needs while also improving the resilience of our network, ensuring investment is targeted at the right time and in the right place. This prioritisation has already been informed by stakeholder feedback at our March 2026 ED3 workshops, where stakeholders prioritised resilience, affordability and ensuring vulnerable, rural and remote communities are not left behind, and will continue to be informed through our pilots, and dedicated 'Pathways to 2050' innovation project.

Our local network is fed by around 120,000 secondary substations and 300,000 feeders. Historically, this scale has made it challenging for DNOs both to identify and to deliver proactive reinforcement on lower voltage assets. We've addressed this through two themes:

- **Enabling better identification** – LV-focused innovation projects and improvements to our data-driven forecasting tools throughout ED2 have improved our ability to identify future network requirements at lower voltages, while greater network visibility through smart metering shows us where the network is not currently performing.
- **Prioritisation** – given the scale of the local network, interventions must be prioritised, with traditional reinforcement evaluated against the potential of smart enablers. This allows us to move from a long

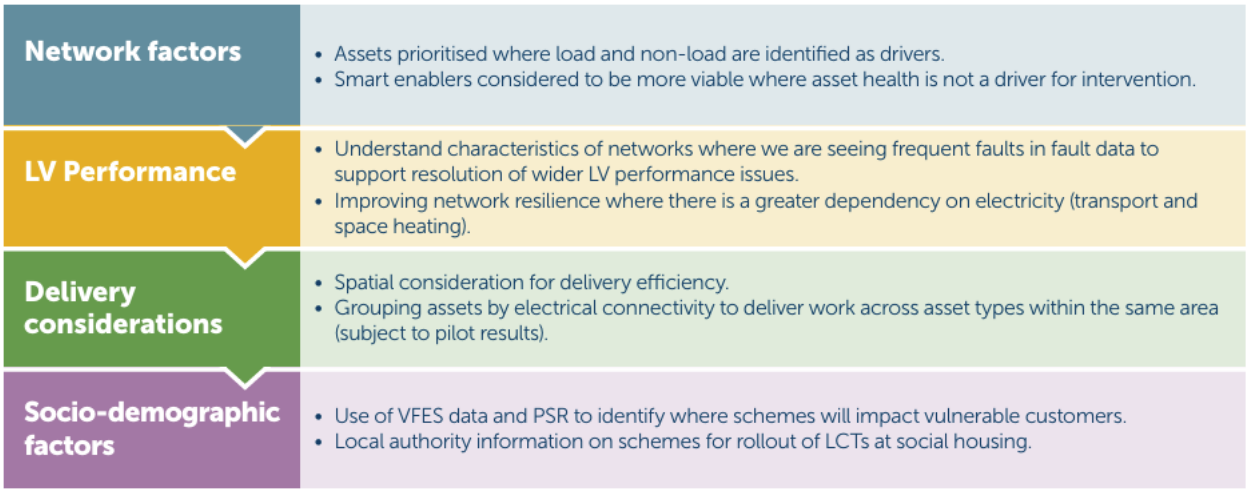
list of modelled outputs to a short list of high-confidence, low-regret schemes that sum to credible volumes for delivery within ED3.

To identify thermal reinforcement volumes proposed for ED3, we've applied tRESP-aligned load forecasts using a range of data and analytics tools, including the SSEN secondary load model and outputs from the LCT CRI innovation project, alongside historic flexibility procurement volumes and forecasts per region. Smart metering data then provides us with average half-hourly voltage measurements, high and low-voltage alerts and substation voltage measurements, which we use to assess the voltage profiles and voltage rationalisation opportunities and identify HV & LV feeders requiring intervention. Together, this analysis enables us to identify:

- Secondary transformers where existing or forecast demand exceeds loading limits,
- LV feeders where projected demand exceeds cable or conductor ratings,
- The location and concentration of properties with looped services or existing LCTs,
- The concentration of assets with potential flexibility capability,
- HV & LV feeders with voltage issues or with high volumes of LCT's which are likely to cause issues soon.

Alongside load-related need, and reflecting stakeholder priorities on resilience, affordability and vulnerability (see Figure 6-3 below), our prioritisation approach takes account of further drivers, so that each intervention addresses as many sources of network need as possible.

Figure 6-3 - Prioritisation approach



Health drivers and asset condition data informs which sections of cable and mains need overlaying or replacing. Where condition-based need coincides with load-related need, interventions are combined into a single scheme so that the replacement asset is sized for future demand and we avoid returning to the same circuits. This minimises disruption, invests for the long term and drives cost efficiency.

We also assess whether local networks have sufficient backfeeds and interconnection to support planned maintenance and fault switching scenarios to ensure network resilience. Upgrades are prioritised where additional interconnection or capacity will allow customers to be restored or kept on supply while sections of network are isolated and considered against the network losses incurred. These are considered from a spatial perspective to drive delivery efficiencies within each locality.

Scores from our Vulnerability Future Energy Scenarios (VFES) innovation project then inform further geographic considerations. VFES rates census areas (LSOAs) on sociodemographic factors and is used to weight interventions towards areas of higher relative vulnerability. This responds directly to stakeholder feedback that LV investment should enable growth while ensuring vulnerable, rural and remote communities are not left behind.

6.5 EXPECTED EFFICIENCIES

Moving from solely reactive, customer-requested interventions to a predominantly planned, programmatic approach is expected to deliver efficiencies in cost, delivery and customer impact.

The largest efficiencies come from combining scope. Packaging service unlooping, LV circuit and secondary transformer upgrades in the same geographic area into single schemes creates operational efficiencies through combined excavation, reinstatement, traffic management and outage planning, and our ED2 pilot learnings indicate significant delivery synergies from extending the programme beyond service unlooping to other LV assets. Planned, area-based delivery also lowers unit costs by avoiding the time and complexity of one-off reactive jobs, which has made it challenging to meet initial ED2 unit rates for service unlooping.

A visible, sustained multi-price control pipeline allows our contract partners to invest in resource and skills, supporting competitive rates and avoiding the cost of stop-start delivery. Reinforcing ahead of need to a long-term specification avoids returning to the same assets as demand grows or health deteriorates, while our Build and Flex approach to portfolio delivery and our use of LV flexibility services helps to further optimise our approach.

Coordinating works with Local Authorities and other utilities also minimises repeat disruption for communities, reflecting stakeholder feedback that works should be coordinated and communicated clearly. At our February 2026 Reliability, Climate Resilience and Network Integrity webinar, 76% of stakeholders emphasised coordinating works to minimise repeat disruption, and 92% supported planned interruptions where the benefits were clearly communicated.

Over the longer term, coordinated planning brings wider benefits. Considering ED3 interventions and preparatory activity in the context of likely ED4, ED5 and longer-term requirements reduces the risk of repeated works, stranded investment or decisions that constrain future options. Aligning future demand requirements with planned asset interventions creates opportunities to provide additional capacity or future-proof assets when work is already required. Considering asset condition, criticality, reliability and future climate exposure together can also improve intervention timing and address several sources of network risk through a single investment.

Coordination also improves environmental, community and delivery outcomes. Integrating environmental considerations at the point of design and optioneering can reduce whole-life carbon, resource use, waste and impacts on nature, and avoids the environmental and community impacts of repeated works. Coordinating interventions geographically improves network readiness for connections and local decarbonisation and better aligns investment with the future needs of communities and local economies. Coordinated programmes also enable common procurement, shared equipment, aligned outages and site access, more efficient use of workforce and contractor resources, and greater visibility of future supply-chain requirements.

7. FUNDING

This section sets out how the LRE plan translates into a proportionate funding request for each licence area. It describes the proposed package of reinforcement and flexibility interventions across the relevant load categories, distinguishes investment sought through baseline allowances from expenditure managed through agile arrangements and uncertainty mechanisms, and explains the outputs through which delivery and consumer protection will be assessed. The approach directs baseline funding towards well-evidenced, low-regret needs, while preserving the ability to respond as demand and flexibility markets develop, helping customers receive timely capacity without paying in advance for investment that may not be required.

7.1 CONSIDERATIONS WHEN MAKING OUR FUNDING REQUEST

We will manage uncertainty over when and where additional capacity is needed, balancing timely delivery with efficient investment to keep costs down for consumers, by applying three principles to our load-related investment plan:

1. Corroborating and strengthening evidence of need through an enhanced approach to DFES and forecasting that will build on the evidence base presented through RESPs.
2. Developing less certain projects to a point where they can be handed over to our project teams for delivery when we've greater certainty so they can be delivered quickly as they are needed.
3. Using flexibility to create capacity quickly so that we're able to respond to urgent customer needs as they arise.

Table 7-1 below lists key factors we've weighed up in determining our overall LRE plan and what funding to request in baseline, or to rely on uncertainty mechanisms to fund should certain triggers be met in period.

Table 7-1 - Summary of our considerations to define load investment categories

Our considerations	Details
Whether the planned activity is reinforcement or flexibility	In SSMD Ofgem makes clear its desire to have flexibility funding ringfenced from reinforcement funding, such that delivery of these activities can be held to account separately. The CV tables have also already required the separate reporting of volumes and costs associated with flexibility.
What planning scenarios and sensitivities they are triggered under	Ofgem has requested DNOs plan against the tRESP pathway to demonstrate what investments are required under this scenario (reported in CV1 & CV2). Following discussion with DNOs, they have further requested DNOs generate and apply a common sensitivity to the investments generated from applying the core planning scenario. This sensitivity is described in Section 4.5.2. This creates a distinction between higher confidence investments which are still required under the sensitivity, and lower confidence investments which are not.
What voltage level of the network they pertain to	Different voltage levels tend to have different investment characteristics. Investments on the higher voltages are of higher value and lower volume, while the inverse is true on the lower voltages. This difference warrants different treatment; fewer, more financially significant projects can be planned and scrutinised in more specific detail, while high volume portfolios of lower value interventions (such as service unloopings) require a portfolio-based approach to planning and appraisal.

Whether the work is a mobilisation activity	Ofgem has indicated that low regret preparatory works for uncertain investments may be appropriate to be included in baseline funding. The key feature of these works is their low regret nature, either because they are of low value, or because they underpin works with a high likelihood of proceeding in future, or both.
The financial materiality of individual investments	Some investments may warrant additional scrutiny due to being high value and separable, making designing specific mechanisms for those investments a proportionate measure.
What key outputs the work delivers for customers	Works can be prioritised if they underpin consumer benefits that are of high social or economic value.

7.2 BASELINE FUNDING REQUEST

7.2.1 LOAD-RELATED EXPENDITURE REQUEST

This section describes our LRE request for our two licence areas based on our load projections. We break down our LRE plan into a series of expenditure categories designed to help understand the makeup and purpose of our plan. For each category, we describe:

- Our proposed package of reinforcement and flexibility interventions
- Our proposed funding between baseline allowances, pre-approved agile allowances and in-period uncertainty mechanisms
- References to where the detailed justifications sit in the business plan, including relevant EJPs, CBA, and BPDT

Below is the summary of the ED3 funding request of our LRE plan:

Table 7-2 - Our LRE request for SEPD and SHEPD

CV table SEPD	Description	2029	2030	2031	2032	2033	Total £m
CV1a	Primary network baseline	165	276	196	163	135	934
CV1b	Primary network uncertainty	40	69	47	19	-7	168
CV2a	Secondary network baseline	29	45	52	57	59	243
CV2b	Secondary network uncertainty	0	1	1	1	5	8
CV3	Fault level related	26	42	69	9	9	155
CV4	NTCC related	0	1	1	1	2	4
Agile		0	0	0	70	70	140
Islands UM		0	0	7	7	15	29
CV1b + CV2b		40	70	47	20	-2	176
Total		**£262m**	**£437m**	**£375m**	**£331m**	**£293m**	**£1,698m**
Baseline		**£222m**	**£367m**	**£321m**	**£234m**	**£210m**	**£1,353m**

CV table SHEPD	Description	2029	2030	2031	2032	2033	Total £m
CV1a	Primary network baseline	222	248	192	85	75	822
CV1b	Primary network uncertainty	117	-83	16	-8	-9	35
CV2a	Secondary network baseline	7	15	18	23	22	85
CV2b	Secondary network uncertainty	0	1	1	1	2	5
CV3	Fault level related	0	0	0	0	0	0

CV4	NTCC related	0	5	15	20	31	72
Agile		0	0	0	24	31	55
Islands UM		49	51	95	163	157	514
CV1b + CV2b		117	-82	17	-7	-7	40
Total		**£395m**	**£237m**	**£337m**	**£308m**	**£309m**	**£1,588m**
Baseline		**£231m**	**£269m**	**£226m**	**£129m**	**£129m**	**£983m**

Islands Investments

For ED3, we've identified £310.3 million of Scottish Islands investment that is sufficiently developed to be included within our baseline plan. This comprises specific network investments for Islay/Jura and Lewis/Harris, alongside £80 million of development funding across the Uists, Mull/Coll/Tiree, Orkney and Shetland to progress the next phase of strategic island investment. These investments total £194m of preapproved baseline funding for island reinforcements, £68m for ED3 development funding, and up to £544m of uncertainty funding, including pots for ED4 development and cable fault contingency.

Further details of this approach and the strategic plans developed can be found in our Islands annex.

Costs

Across our EHV portfolio, we've studied 82 zones, with 63% of these assessments recommending flexibility as the most economic and efficient option during the ED3 period. Initial studies of over 6,000 secondary network assets indicate our forecast use of flexibility across HV and LV zones is set to increase significantly in ED3, being a key tool for managing uncertainty and deliverability driven by sensitivities to future LCT forecasts. The outcomes of these assessments are illustrated in Table 7-3 below:

Table 7-3 - Summary of flexibility assessments for projected use in ED3 in planning use cases

Voltage	Region	MW	MWh	Flex Cost (m)
EHV	SEPD	129.84	1,359.83	[redacted]
	SHEPD	107.10	2,097.13	[redacted]
HV/LV	SEPD	20.11	972.68	[redacted]
	SHEPD	5.23	191.97	[redacted]
	Total	**262.28**	**4,621.61**	[redacted]

When developing our ED2 portfolio, our forecast flexibility costs derived from the CEM tool were £4.6m. Our forecast expenditure for planning use cases of flexibility in ED3 then represents a 309% increase, reflecting our commitment to push flexibility as far as we can.

This represents our view at this point in time, reflecting our current assessment of certainty of future load growth and deliverability. In line with our annual forecasting processes, we'll continue to evaluate where flexibility can be used within the period as certainty increases, and to support ongoing deliverability and meeting customers' capacity needs in a timely and cost-effective manner. Further detail is provided in our (ED3-S10) DSO strategy on how we intend to develop our markets further to maximise participation through our FlexForward procurement strategy.

Interactions with ED2 Funding Arrangements

The final determination process for the ED2 LRE UM, which is funding for ED2 works and mobilisation for ED3, is not complete at the point of submitting ED3 business plan. We've completed our ED3 LRE plan based on our resubmitted submission from July 2026.

Our plan for managing this uncertainty is to continue to work closely with Ofgem to fully understand their decision and to define the appropriate treatment of specific investments that we cannot reach agreement on for mobilisation in ED2. Following Final Determination of the LRE UM, we may need to revise our ED3 plan, however confirmation of this is still outstanding. See (SSEN_ED3_CrossoverAnnex) Crossover Paper for further detail.

Similarly, the ED2 HOWSUM mechanism has already agreed some funding for works required on the Scottish Islands- further detail on this is available in our (ED3-S17) Islands Strategy.

7.2.2 DESCRIPTION OF OUR INVESTMENT CATEGORIES

For our 132kV and EHV networks, our ED3 LRE funding request is made up of 175 Major Projects, 96 in SEPD and 79 in SHEPD. We've developed 77 Engineering Justification Papers for Major Projects over £6 million, demonstrating the need for investment, the options considered, and the value delivered for consumers. For the remaining projects under £6 million, we've carried out the same options assessment and created internal facing technical reports, again evidencing needs case, optioneering and outlined investment proposals. The full list of projects can be found in Appendix 1.

Key asset types can be found within the table below:

Table 7-4 - Distribution of asset types in SHEPD and SEPD (Baseline Expenditure)

Output	North	South	Total
EHV and 132kV Transformers (Each)	114	67	181
EHV and 132kV Overhead Line (km)	786	310	1,096
EHV and 132kV Underground Cable (km)	246	401	647
EHV and 132kV Subsea Cable (km)	92	0	92
EHV and 132kV Circuit Breakers (Each)	274	425	699
HV Transformers (Each)	2,372	1,393	3,765
HV Overhead Line (km)	190	14	204
HV Underground Cable (km)	94	123	217
HV Circuit Breakers (Each)	199	150	349
LV Overhead Line (km)	1	14	16
LV Underground Cable (km)	20	321	342
LV Service Upgrades	5,712	14,029	19,741

On our high voltage network, our approach is inherently more reactive than EHV investment, as it is planned closer to need and delivered over shorter timescales. As a result, schemes in early years of ED3 have justified intervention requirements and require immediate progression reflected in our baseline funding request, while interventions in later years remain more indicative as uncertainty around the timing and location of future constraints is resolved. Consequently, flexibility will play a key role in managing uncertainty

across the HV portfolio, particularly the aggregate impact of smaller and medium-sized connections whose size, timing and location are uncertain, while also supporting the deliverability, sequencing and prioritisation of investment.

For ED3, we're adopting a programmatic approach to LV reinforcement, recognising that many network constraints arise from common growth drivers and require repeatable interventions across multiple locations. Rather than developing individual investment cases for every scheme, we've grouped similar reinforcement needs into strategic investment programmes supported by representative evidence, network modelling and cost benefit assessment.

This approach enables us to efficiently address widespread demand growth driven by electrification, while ensuring investment remains targeted, proportionate and responsive to local network conditions. Individual schemes will continue to be identified and prioritised through ongoing network planning and optioneering processes, with delivery focused on those areas where customer demand and network utilisation demonstrate the greatest need for reinforcement. This programmatic work will include our work to deliver service unlooping which will allow for greater delivery efficiencies when combined with other works on LV networks.

Further information relating to our detailed LV investment programme can be found in Section 4.

7.3 MANAGING UNCERTAINTY & OUTPUTS

In the SSMD, Ofgem set out its position on managing load-related uncertainty. Ofgem's ED3 Sector Specific Methodology Decision (SSMD) recognises that electricity demand will increase, but that there is substantial uncertainty over the scale, timing and location of new load. It therefore proposes a more phased, evidence-led approach to load-related investment as detailed in Table 7-5 below:

Table 7-5 - SSMD principles

SSMD principle	What it means for load uncertainty
Low-regret baseline funding	DNOs must show that an intervention is highly likely to be required during ED3, rather than relying only on long-term demand forecasts.
"Build and flex" by default	DNOs must demonstrate that they have maximised existing capacity through flexibility, such as demand-side response, smart charging, storage and controlled exports, before conventional reinforcement is funded.
Manage residual uncertainty in-period	Where the need, timing or solution is not sufficiently certain at the outset, in-period funding adjustments can allow investment to be approved, increased or deferred as demand materialises.
Protect consumers from premature investment	Investment that gets materially ahead of demand could increase bills before consumers receive the associated benefits.

We propose a suite of mechanisms to address the uncertainties across need scope and timing including traditional reopeners, and more agile funding pots which support the use of additional flexibility (Table 7-6). This approach protects consumers from funding investment before need is confirmed, while enabling SSEN to respond efficiently as demand and project requirements become clearer.

Table 7-6 - Investment by funding mechanism

Funding	SEPD	SHEPD	BPDT Tables
Baseline Ex-Ante LRE	£1,353m	£983m	CV1a/CV2a/CV3a/CV4
Agile Contingency Pot	£140m	£55m	M25

Uncertainty Mechanism CVb	£176m	£40m	CV1b/CV2b
Uncertainty Mechanism Islands	£29m	£514m	M25

7.3.1 UNCERTAINTY MECHANISMS

We propose targeted uncertainty mechanisms for investment that cannot be defined confidently at the start of ED3. This includes £144 million for primary and secondary reinforcement driven by the full Holistic Transition tRESP scenario, but not the revised weakened scenario as set out in Ofgem's Annex 2. This funding is for thermal and voltage reinforcements only, with no current provision for fault-level reinforcement. Where need or optioneering remain less certain for our island networks, we have moved **£500 million** into uncertainty, allowing us further time to ensure the need materialises, and our investment represents the best overall solution.

Additional funding may be considered within period for large capacity projects triggered by Strategic Energy Needs, clusters of major connections activity and transmission related activity. Within ED2 examples of this are our HOWSUM investments. We will continue to monitor new developments on our network and engage with local stakeholders to consider the most appropriate investments to meet their requirements as needs become more certain.

As stated earlier, the load related LV reinforcement proposed in our ED3 plan will directly enable up to 176,000 homes to install LCTs. To identify the reinforcement volumes proposed in ED3 we've used a variety of data and analytics tools including the SSEN secondary load model and the LCT CRI innovation project outputs.Table 7-7, Table 7-8 and Table 7-9 summarise LV programmatic investment within ED3. This includes the funding request and the associated volume of work delivered:

Table 7-7 - Secondary transformer investment summary

Secondary Transformers (GMTs and PMTs)	LV Strategy: Secondary Transformer reinforcement
Funding request (£m)	[redacted]
Extension from ED2?	N
Description	Reinforcement of Pole Mounted and Ground Mounted Secondary Transformers across both SEPD and SHEPD licence areas. Both load and non-load drivers for reinforcement have been considered to ensure efficient identification of reinforcement work. For this investment we'll deliver 3,944 new secondary transformers (1,446 in SEPD and 2,498 in SHEPD), releasing a total of 419.33 MVA.
Reference to IDP	LV_1 *SSEN_LRE_SecondaryTransformers*

Table 7-8 - LV circuits investment summary

LV Feeder Mains	LV Strategy: LV Circuit reinforcement
Funding request (£m)	[redacted]
Extension from ED2?	N
Description	Reinforcement of LV feeder mains across both SEPD and SHEPD licence areas. Optimised across load and non-load drivers to mitigate loading issues while improving the resilience of our network to reduce outages due to faults.

	For this investment we'll deliver 466.49km of LV circuit reinforcement (444.39km in SEPD and 22.10km in SHEPD).
Reference to IDP	LV_2 *SSEN_LRE_LV_Circuits*

Table 7-9 - Service unlooping investment summary

Service unlooping	LV Strategy: Service unlooping
Funding request (£m)	[redacted]
Extension from ED2?	N
Description	Proactive unlooping of looped services to enable connection of LCTs. Capability of each looped service has been estimated using outputs from the LCT Connections Readiness Indicator innovation project. T-RESP projections for domestic LCT uptake have been deployed alongside this to create a forecast for when proactive de-looping should be carried out at a property level. For this investment we'll deliver 19,741 new services (14,029 in SEPD and 5,712 in SHEPD), resulting in up to 39,482 properties unlooped.
Reference to IDP	LV_3 *SSEN_LRE_ServiceUnlooping*

We've identified £507 million of strategic island investment for uncertainty mechanism funding, reflecting uncertainty in project scope, engineering solutions and costs. Our baseline request includes £68 million of development funding to mature these projects and assess alternatives, including third-party flexibility and repowered diesel generation.

7.3.2 MANAGING RESIDUAL IN-PERIOD UNCERTAINTY

Our load portfolio is an optimised mix of flexibility and network-build solutions, based on our current understanding of investment timing and the availability of flexibility. Uncertainty remains over when investments will be required and the role flexibility could play within each technical solution. Through our (ED3-S10) DSO strategy, we plan to develop new markets and services and incorporate them into network planning. Our output and funding envelope should recognise both the additional flexibility available at portfolio level and our ambition to deliver more.

Traditional Uncertainty Mechanisms address significant uncertainty over the timing, scale or scope of investment at the start of a price control. They protect consumers from premature investment, but are less effective at managing residual in-period uncertainty associated with build and flex. Ofgem needs to recognise many factors can change whether build or flex is the most efficient option, and companies should not be disincentivised from deploying more flexibility.

We therefore believe an agile in-period mechanism is needed to support flexibility and timely load delivery before administrative reopeners are used. This should operate alongside a portfolio mechanism that manages and tracks outputs from the load-related investment programme.

7.4 MANAGING OUTPUTS

Our preferred approach is a proportionate output framework with the Load Index Risk Metric as the primary measure of portfolio-wide delivery of primary reinforcements, with targeted project specific PCDs for a small number of high-value, discrete investments where required. For secondary investments we propose the continued use of the volume drivers to aligns funding and outputs with realised demand growth, provides appropriate consumer protection and retains the flexibility required to respond to uncertain uptake of low-carbon technologies.

This approach balances accountability with flexibility, allowing efficient adaptation to changing customer needs and demand forecasts while maintaining clear regulatory oversight of the outcomes delivered for consumers. We'll set project specific PCDs for Load as part of Final Determinations with Ofgem.

7.5 LOAD INDEX RISK METRIC

We propose adapting and enhancing the RIIO-ED1 Load Index Risk Mechanism (LIRM) as the primary output for LRE spend. We propose using LIRM and the Load Index to track delivery, manage timing uncertainty and protect consumers from premature investment. This is an enhancement of an existing ED1 mechanism that assessed whether a Distribution Network Operator delivered the expected reduction in capacity-related risk at higher-voltage substations. We will use the LIRM mechanism to determine a LIRM risk reduction target to be delivered as an output in ED3 with a baseline funded settlement.

7.5.1 LIRM OVERVIEW

- Each substation is assigned a Load Index (LI) based on forecast peak demand relative to its firm capacity.
- Higher LI bands indicate that demand is approaching or exceeding available capacity and therefore represent greater network risk.
- Substations are converted into Load Index risk points, giving the DNO an overall risk position.
- Ofgem compares the company's delivery against the LIRM risk reduction target (a delta between with and without intervention) with the baseline funded through its settlement.
- The assessment allows for justified changes such as revised demand forecasts, changes in network configuration and efficient alternatives to conventional reinforcement.
- Where a DNO delivers less risk reduction than funded, Ofgem may recover allowances to prevent consumers paying for reinforcement that was not required or delivered.
- Where it delivers additional justified risk reduction, this may be recognised where the extra work was efficient and provided genuine consumer benefit.

In simple terms, LIRM reconciles the reinforcement funding a DNO received with the load-related capacity risk it removed. It is the load-related equivalent of an output closeout mechanism: companies are held accountable for managing substation capacity risk, rather than simply spending an allowance or completing a fixed list of schemes.

Our BPDT submission and supporting IDPs will set out the required investment, optimised against our current view of monitoring, flexibility and network build. This will establish the proposed change in the Load Index Risk Mechanism target and a baseline unit-cost-of-risk intervention threshold.

7.5.2 LIRM DEADBAND

We propose a 20% deadband around the LIRM risk output. Within the deadband, the portfolio would be treated as fully delivered: over- or under-delivery would require no further justification and would be treated as 100% justified. Outside the deadband, the licensee would need to justify the full amount of any over- or under-delivery. Ofgem would then determine the justified amount and apply any resulting funding adjustment.

We propose using the deadband to manage timing uncertainty, including where factors outside our control move asset energisation from ED3 into ED4.

Our Drayton 132kV investment illustrates this issue. The preferred option depends on the timing of transmission works and the availability of the proposed Didcot GSP connection point, which is subject to the Modification Application process and associated transmission reinforcement. Identified mitigations - including active customer connection management and strategic 33kV load transfers - provide confidence that emerging constraints can be managed if transmission delivery schedules change.

While forecast demand growth remains sensitive to the timing of customer connections, the requirement for reinforcement is supported by both DFES projections and significant contracted and anticipated customer demand across Milton, Harwell, and Culham. In summary, the SSEN-controlled scope is considered deliverable within the proposed programme, while final energisation remains conditional on confirmation of the Didcot transmission interface.

This type of transmission dependency occurs across both licence areas as can be seen below in Table 7-10:

Table 7-10 - Transmission dependencies

Reference	Licence area	Investment
SEPD_LRE_7	SEPD	Leamington Park LRE EJP
SEPD_LRE_9	SEPD	Brentford Capacity Upgrade LRE EJP
SEPD_LRE_29	SEPD	New Bicester West BSP LRE EJP
SEPD_LRE_85	SEPD	Drayton BSP LRE EJP
SHEPD_LRE_2	SHEPD	Abernethy – Abernethy 33kV Circuits & Errol Primary Transformer
SHEPD_LRE_233	SHEPD	Dalcross GSP Integration Works
SHEPD_LRE_201	SHEPD	Orkney 2050 Strategic Plan
SHEPD_LRE_203	SHEPD	Shetland 2050 Strategic Plan
SHEPD_LRE_208	SHEPD	Outer Hebrides 2050 Strategic Plan
SHEPD_LRE_62	SHEPD	Inverness – Inverness GSP: 3L5 and 4L5 Circuits to Waterloo Primary

In addition to the Transmission Dependency, we've a dependency on the third-party planning and consents for customer connections, and our view is that a deadband is the most appropriate way of managing these. The alternative mechanism of an exceptions process will increase the burden on Ofgem and DNOs and offer limited value to consumers.

7.6 LIRM & AGILE FUNDING

As set out in the Build & Flex section, we propose a £195 million Agile Contingency Pot alongside our baseline ex-ante allowances to adjust allowances where flex is unavailable, or new projects are required to be delivered within ED3 through additional flex.

This may result in over-delivery of network Load Index risk reduction, where a company delivers more risk reduction than its baseline. We propose that Ofgem assesses the additional delivery, after adjusting for non-intervention risk changes and other factors outside the company's control.

- We must demonstrate that the over-delivery is genuine, efficient and justified — for example, that it was needed to manage an emerging asset risk and represents value for consumers.
- Over-delivery is not rewarded automatically. Ofgem can reject or reduce the adjustment where the work was unjustified, inefficient, already funded elsewhere, caused by timing changes, or does not provide enduring risk reduction.
- Ofgem uses the relevant unit cost of risk to translate accepted additional risk reduction into a funding adjustment. The closeout process therefore aims to fund efficient additional risk reduction while preventing companies from earning extra revenue simply by exceeding output volumes without demonstrating consumer value.
- To protect consumers, we propose that this is capped at £195m to limit the overall usage and provide the correct funding levels before accessing administrative UMs.

7.6.1 KEY DIFFERENCES FROM NARM

Unlike NARM, funding would be accessible from 100% of the target output; delivery would not need to reach 105% of the target before funding became available.

7.7 FLEXIBILITY SUBSTITUTIONS

We propose an allowance-based cap on flexibility substitutions to provide an appropriate check and balance while encouraging DNOs to deploy flexibility where it offers better value than immediate reinforcement. This would reward efficient delivery, reveal demand more clearly and improve visibility of when future network build is genuinely required.

Ofgem's move to a "build and flex" approach for ED3 requires DNOs to make greater use of flexibility alongside reinforcement. We've identified c£195m of primary projects that are close to being viable for economic deferral through market-based flexibility. Realising this potential requires the ability to substitute flexibility for funded build where updated demand, market availability and delivery evidence show that flexibility is the more efficient solution.

A fixed ex-ante programme locks in a delivery pathway before the need for reinforcement and the availability of flexibility are fully known. A substitution mechanism is therefore needed to avoid disincentivising flexibility and to allow the portfolio to be optimised in period. It would enable DNOs to replace planned build with flexibility where this maintains network compliance, lowers costs and preserves the option to reinforce later if demand materialises.

Flexibility and access arrangements can typically defer scheme completion by one or two years, maintaining compliance while providing time to confirm that demand will materialise and physical reinforcement is justified. Substitution is essential to capture this value without penalising DNOs for changing the delivery solution while still achieving the required load-risk output. We propose that 15% of the allowance is substitutable based on the potential for flexibility solution to mature in ED3.

7.8 CLOSE OUT

In support of the LIRM mechanism Ofgem must develop a close out process that determines whether funding should be retained, returned or adjusted. This process must:

1. **Compare like with like**
   Ofgem reconciles the baseline and actual position so that changes in methodology, data or assumptions do not create artificial over- or under-delivery.
2. **Separate non-intervention changes**
   Changes in asset risk not caused by company interventions—such as reduced demand or modelling

changes — are treated as Non-Intervention Risk Changes and removed from intervention delivery where appropriate.

3. **Prevent double funding**
   Delivery funded through another mechanism, price-control deliverable or allowance should not also receive funding through LIRM and there should be clear boundaries between NARM and LIRM
4. **Recognise crossover projects appropriately**
   Projects delayed beyond ED3 and continuing into first two years of ED4, are assessed under specific crossover rules to align funding with actual delivery and avoid double recovery or inappropriate clawback of allowances.

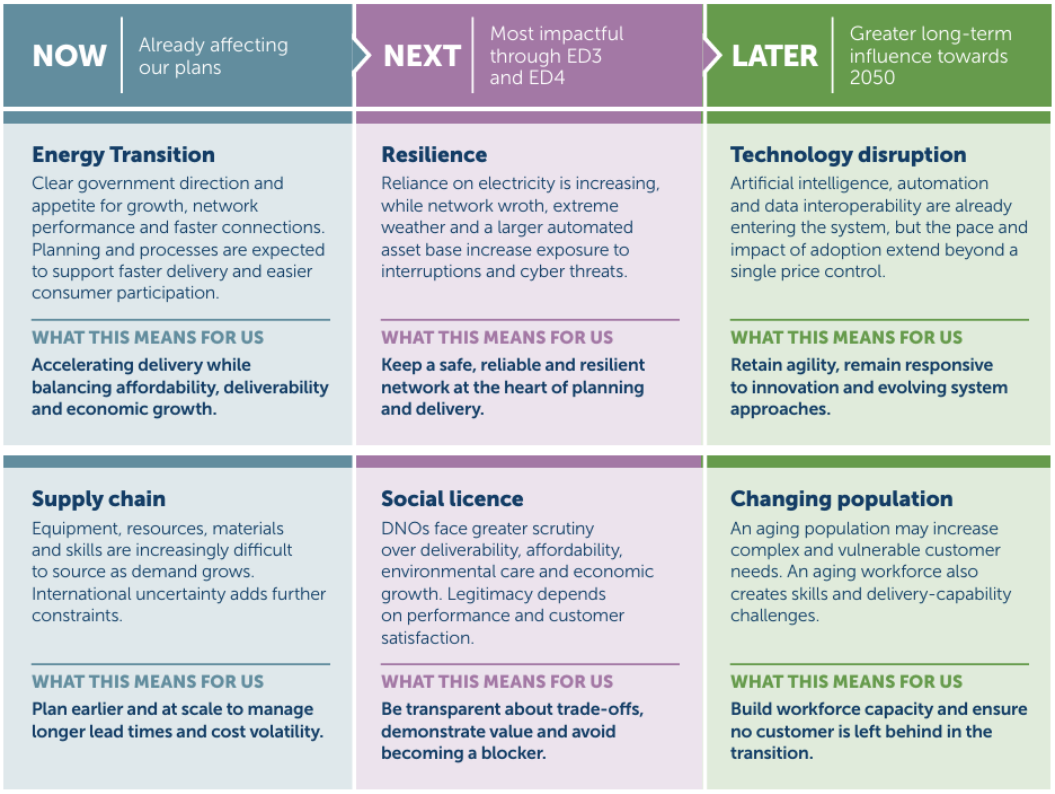
8. RISKS AND MITIGATIONS

This section provides a proportionate summary of the principal risks and dependencies affecting delivery of the ED3 LRE plan, including workforce and skills, supply-chain capacity, network access and outages, consents and land rights, transmission interfaces, demand uncertainty and flexibility-market liquidity. It explains the specific mitigations being applied through early mobilisation, coordinated programme planning, Build and Flex, substitutability and ongoing forecast review, while avoiding duplication of the fuller analysis in the (ED3-S05) Delivery Strategy and (ED3-S02) Long-Term Integrated Network Plan (LINP). These controls are intended to maintain timely access to capacity, safety and reliability while reducing the risk of delay, inefficient expenditure or additional cost to consumers.

8.1 LONG TERM TRENDS

Our (ED3-S02) Long-Term Integrated Network Plan (LINP) considers the key long-term trends and uncertainties that will shape the development of our network. It brings together the implications of changing demand, asset needs, climate resilience and wider network requirements, helping us understand how these drivers interact and inform our investment choices over the long term.

Figure 8-1 - Key trends shaping our network over the short, medium and long-term



8.2 WORKFORCE AND SKILLS AVAILABILITY

The scale of investment required during ED3 will increase demand for skilled and authorised personnel across engineering, project delivery and operational functions. In particular, roles such as jointers, linespersons, protection engineers, commissioning engineers and Senior Authorised Persons (SAPs) are subject to industry-wide shortages and often require several years to achieve competence and authorisation. Failure to secure sufficient capability could impact programme delivery schedules and network access arrangements.

To mitigate this risk, SSEN has adopted a long-term workforce strategy based on demand-led forecasting and skills modelling. Recruitment, apprenticeship, reskilling and training programmes have been initiated during RIIO-ED2 to develop capability ahead of ED3 requirements. This includes targeted development of critical operational and engineering roles, together with the use of strategic delivery partners to provide flexibility and resilience where required. Workforce requirements are monitored through established governance processes and are supported by mobilisation funding activities that seek to align workforce readiness with future delivery volumes.

8.3 SUPPLY CHAIN AND LONG LEAD EQUIPMENT

Global demand for transmission and distribution infrastructure continues to place pressure on the availability of critical equipment, including transformers, switchgear, cables and specialist contractor resources. Increased competition across the wider energy sector may lead to longer lead times, cost volatility and delivery delays if procurement activities are not undertaken sufficiently early.

SSEN has implemented a proactive supply chain strategy to reduce exposure to these risks. This includes long-term framework arrangements, early engagement with suppliers, capacity reservation where appropriate and advance procurement of long lead-time equipment. The mobilisation programme also enables early design, specification and procurement activities to be undertaken before ED3 commences,

helping to provide greater certainty of delivery and reducing the risk of supply chain constraints becoming a critical path issue. Supply chain performance and market conditions are continuously monitored through SSEN's programme governance framework.

8.4 NETWORK ACCESS, OUTAGES AND OPERATIONAL CONSTRAINTS

A significant proportion of ED3 reinforcement activity will require planned outages and access to operational assets. Delays in securing outages, changes in network conditions, or competing operational priorities could affect programme sequencing and delivery timescales. The challenge is particularly important for larger EHV and 132kV schemes where outages require significant coordination across multiple stakeholders.

Mitigation measures include early outage identification and planning, integration of operational requirements into programme development, and coordination between planning, delivery and network operations teams. SSEN has established governance arrangements to ensure outage requirements are identified well in advance and that delivery plans are developed alongside network access requirements. Delivery programmes are also structured to provide flexibility where activities need to be re-sequenced due to operational constraints.

8.5 CONSENTS, LAND RIGHTS AND ENVIRONMENTAL APPROVALS

Many ED3 reinforcement projects require planning permissions, environmental approvals, wayleaves, easements or land acquisitions. Variability in consenting timescales and stakeholder requirements can create programme risk, particularly for larger strategic reinforcements and new substation developments.

SSEN's approach is to progress these activities as early as possible within the project lifecycle. Strategic Development Plans and early project development activities provide visibility of future network requirements, allowing engagement with landowners, planning authorities and other stakeholders to commence ahead of construction. Mobilisation funding supports feasibility work, surveys, land acquisition activities and consent preparation during RIIO-ED2, reducing the risk of delays at the start of ED3. Where appropriate, delivery programmes maintain flexibility to substitute, or re-sequence, projects should consent risks materialise.

8.6 DEPENDENCIES ON TRANSMISSION AND WHOLE-SYSTEM COORDINATION

Several ED3 load-related schemes have interfaces with the transmission network, including dependencies on transmission capacity, transmission reinforcements, outage coordination and wider whole-system planning activities. Delays to transmission works or changes in transmission assumptions could affect the timing and benefits of some distribution reinforcements.

To manage these dependencies, SSEN maintains ongoing engagement with NESO, National Grid Electricity Transmission and Scottish Hydro Electric Transmission through established planning and operational forums. Strategic Development Plans and DGIF processes are designed to consider whole-system requirements and transmission interfaces at an early stage. Where appropriate, reinforcement strategies also incorporate phased delivery and flexibility solutions to maintain customer outcomes while wider transmission developments progress.

8.7 DEMAND FORECAST AND INVESTMENT NEED UNCERTAINTY

Future network requirements are inherently uncertain, particularly in relation to the pace, scale and location of demand growth from low-carbon technologies, new connections, major demand customers and wider economic development. There is therefore a risk that actual demand develops differently from current planning assumptions, affecting

the timing, scale or location of individual reinforcement requirements. This could result in investment being committed ahead of need or, conversely, insufficient capacity being available where demand develops more quickly than anticipated.

We mitigate this risk through our structured planning process, combining tRESP planning inputs, contracted connections, stakeholder and local intelligence, sensitivity analysis and regular forecast updates. This enables investment requirements to be reassessed as new evidence emerges. Crucially, our Build and Flex strategy enables us to use flexibility where the needs case is more exposed to demand forecast uncertainty, maintaining optionality and reducing the risk of committing to inefficient or premature reinforcement. This allows us to defer or adapt investment decisions while confidence in the timing, scale and location of demand increases, without compromising our ability to provide capacity when it is required. Uncertainty mechanisms provide a further route for requirements that cannot be sufficiently evidenced for baseline funding at the start of ED3.

8.8 FLEXIBILITY RISKS

Our plan relies on flexibility to ensure capacity is available wherever customers are likely to require it during ED3, so we must develop and sustain a reliable and resilient flexibility market and mitigate the risk of non-delivery. The industry has matured in this area and contracting arrangements and market structures now provide standard means of mitigating non-delivery of services. From a planning perspective, the key risk at distribution is insufficient liquidity to deliver flexible solutions at an economical level, which arises where a constraint has too few resources connected downstream to influence it. We mitigate this through our technical and economic viability assessment, which examines market depth, window length and benchmarked cost, and through early engagement, typically three years ahead of required service delivery, so that the market is ready in good time or alternative arrangements can be made. Where liquidity or economics are not yet proven, we keep schemes open and retest annually as forecasts and market evidence update, so that no opportunity is foreclosed.

Substitutability is our principal protection against both the risk of flexibility not delivering and the risk of not meeting need in time. Under LIRM we are accountable for the load-related risk removed, not for completing a fixed list of schemes, so where flexibility at one site proves unavailable, uneconomic or insufficiently liquid, we can build that site and flex another that can, while still delivering the required risk reduction. Where flexibility is no longer efficient or economic across our range of use cases, the Agile Contingency allows us to pivot to build in place of a reopener. We take build decisions as late as is safe, triggered by planning lead times that cover the full time to energisation, and flexibility continues to support the network and connections during construction. Capacity is therefore delivered when needed whether or not a particular flexibility solution materialises, without consumers funding capacity ahead of need.

APPENDIX 1: STRATEGIC ENERGY NEEDS

This appendix is provided in a separate excel file. Please refer to (ED3-S01-A01) Load Related Expenditure Annex Appendix 1 Strategic Energy Needs.

APPENDIX 2: HISTORIC DEMAND

This appendix is provided in a separate excel file. Please refer to (ED3-S01-A02) Load Related Expenditure Annex Appendix 2 Historic Demand.

APPENDIX 3: FULL STAKEHOLDER ENGAGEMENT TABLE

Policy area (theme)	Type of engagement undertaken	Stakeholder groups	Summary feedback	Impact on business plan
Supporting local economic growth, powering our communities and supporting Local Authorities	DSO Surveys, DSO Autumn Series, Connections Forums, DNO Working Group on Community Energy, Consumer Priorities Research, Utility Week Virtual Roundtables, Have Your Say Webinars, Southampton Energy Coalition Conference, GB Energy Bilateral, ESC Bilateral ED3 Stakeholder Engagement Workshops, March 2026 (Perth, Reading & online deliberative workshops, independently facilitated): Session 1 - Planning for the ED3 price control.	Local Authorities, Community Energy Groups, Housing Developers, Consultants, DER Customers, ICPs/IDNOs, Domestic Consumers, SMEs, MPs, Academia, Major Customers, Government Bodies, NESO, Energy System Partners	Stakeholders consistently emphasised that coordinated, place-based planning is essential to enable local economic growth and community energy development. Local Authorities reported lacking resources and relying heavily on DNO guidance for future load requirements, reinforcing the value of SDPs, LENZA and RESP support tools. Community energy groups highlighted persistent financial and capacity barriers, requesting clearer pathways, coordinated support and more predictable, long-term investment signals. The Southampton Energy Coalition validated SSEN's role as an enabler rather than a blocker, with stakeholders endorsing our investment programme and committing political advocacy for ED3. Stakeholders also called for broader, more inclusive definitions of community energy, strong cross-government and NESO-LA-DNO coordination, and place-based, multi-technology delivery models to address constraints and maximise local benefits.	The business plan now positions SSEN as a strategic planning partner with trusted collaboration with LAs, NESO and government bodies. LENZA and LAEP+ have evolved into integrated RESP-aligned capabilities enabling scenario-based regional planning. Dedicated community energy coordination has been established with a target of working relationships with 72 Local Authorities. LA Development Plans will be co-developed to align network investment with local priorities. The Southampton engagement provides a case study demonstrating multi-party consensus on investment need, with Coalition-identified grid constraints integrated into ED3's load planning evidence base. A joint SSEN-ESC-LA/NESO working group will tackle planning misalignment early and de-risk centralised RESP uncertainty.
Investment in the network to accelerate the provision of capacity, enabling and accelerating connections	DSO Surveys, Connections Forums, DSO Autumn Series, Consumer Priorities Research, Major Business Priorities Research, Utility Week Virtual Roundtables, Have Your Say Webinars, GB	DER Customers, ICPs/IDNOs, Housing Developers, Consultants, LAs, I&C Customers, Domestic Consumers, SMEs, Community Energy	Stakeholders made strong calls for faster, clearer connections, with better curtailment visibility and forecasting, while different stakeholder groups highlighted varying concerns around affordability, accessibility and certainty. This was reinforced by SSEN's Business Priorities Research with large energy users, which found greater emphasis on faster	An enhanced electrification advisory function will be operational from 2028, providing tailored pre-application optioneering support to customers including community energy groups, Industrial & Commercial customers and those seeking to install LCTs. This will deliver integrated customer optioneering with customer-facing tools across all

	Energy Bilateral, Southampton Energy Coalition, Regen Bilateral ED3 Stakeholder Engagement Workshops, March 2026 (Perth, Reading & online deliberative workshops, independently facilitated): Session 1 - Planning for the ED3 price control.	Groups, MPs, Academia, Major Customers	and easier connections than among domestic and general business customers. For businesses considering a new connection, speed of delivery was the most frequently selected priority, alongside a simple process, knowledgeable support and greater certainty over costs and timescales. Remote communities, particularly islands, highlighted resilience and outage reduction as priorities. Community groups raised concerns about disproportionate costs and complex requirements. Stakeholders emphasised the need for earlier, strategic and anticipatory load planning, consistent with the Business Priorities Research finding that long-term planning was the highest-ranked detailed priority for large energy users. This would help avoid the network becoming a blocker to electrification, heat pump rollout, EV charging and wider economic activity. Data centre growth, AI clusters and other high-demand industries were cited as significant step-change load drivers. LCT providers highlighted that outdated processes and unpredictable enabling-works timelines slow deployment. Stakeholder bilaterals emphasised that community energy projects often emerge late but can scale quickly once funding aligns, increasing the risk of volatile load and strengthening the case for ahead-of-need investment.	voltage levels. A target of ≥90% customer satisfaction for DSO pre-application support by 2030 has been set, with an explicit commitment to improvement across the customer journey. The plan strengthens anticipatory load planning and early signalling of reinforcement, with scenario-based load modelling reflecting late-emerging community and public-interest load. Queue management principles for sub-5MW projects are being reviewed for fairness and transparency. Place-based coordination models with Local Authorities are being piloted for community and public-interest projects. Our Southampton investment programme demonstrates strategic, ahead-of-need approach.
Strategic and holistic long term development plans	DSO Surveys, DSO Autumn Series, ODM Consultation, Consumer Priorities Research, Utility Week Virtual Roundtables, Have Your Say Webinars, Day Ahead Flexibility Markets Webinar, SDP Methodology Consultation, DNOA Consultation, Value of Lost Load Research ED3 Stakeholder Engagement Workshops, March 2026 (Perth, Reading & online deliberative workshops, independently facilitated): Session 1 - Planning for the ED3 price control.	Local Authorities, Consultants, Developers, FSPs, Technology Providers, Community Groups, System Operation Specialists, Domestic Consumers, SMEs, Regulators, Academics, Trade Associations	Stakeholders placed critical importance on accurate, granular, standardised data and called for improved forecasting, real-time data and headroom visibility. Consumer research showed reliability/resilience (28%) and value for money (26%) are top priorities, with 45% struggling to pay bills occasionally and customers ranking 'helping bring down bills in the long term' (10.1%) as the most important action. Stakeholders consistently called for clearer, jargon-free messaging across RESP, SDPs and ED3 planning, with requests for worked examples and scenario transparency to understand how these priorities are being embedded	Earlier whole-system planning will be embedded as a core strategic planning capability, enhancing our in-house forecasting capability across all voltages, we'll use probabilistic modelling tools to produce network needs assessments incorporating voltage and losses. Automated CEM-based options assessments enable more transparent decision-making. The plan now includes clearer strategic alignment with NESO, greater transparency on how SDPs, DFES and RESP inputs shape long-term investment needs, and improved communication on the rationale for anticipatory reinforcement. VoLL insights justify proactive, anticipatory interventions at LV, not only traditional reinforcement. Stakeholder feedback on transparency, coordination and flexibility deployment has strengthened the stakeholder engagement approach and reinforced the drivers for change narrative.

Using flexibility to maximise network and system capacity	DSO Surveys, DSO Autumn Series, Day Ahead Flexibility Markets Webinar, ODM Consultation, DNO Working Group on Community Energy, Utility Week Virtual Roundtables, Have Your Say Webinars, Energy Efficiency Roundtable ED3 Stakeholder Engagement Workshops, March 2026 (Perth, Reading & online deliberative workshops, independently facilitated): Session 1 - Planning for the ED3 price control.	FSPs, Aggregators, Storage/Renewable Providers, CMZ Operators, Community Energy, Consultants, LAs, Technology Providers, Academics, System Operation Specialists	Stakeholders value flexibility but barriers including onboarding complexity, and clarity around dispatch decisions and curtailment remain unclear. The move to day-ahead flexibility markets saw 80% of stakeholders indicating they are likely to participate, and all respondents felt SSEN is using flexibility services effectively. The flex market is growing with 2.6 GW tendered and 915 MW awarded. However, disproportionate telemetry requirements hold back smaller actors, and community groups currently lack capability to participate effectively in flexibility markets. Stakeholders supported community batteries and dynamic access products as load-relieving alternatives. Flexibility providers noted the need for long-term clarity on when flexibility will be used to defer reinforcement, with the understanding that flex is an option, not a universal substitute for load investment.	To support further development of flexibility products and drive lower costs, a market incubator team will be established, scaling its applications and engaging a broader range of customers. To enable the seamless use of flexibility and these new use cases, our technology and control systems also need to be scalable and seamless. We've proposed to further develop the Systems for Flexibility technology stack with DERMS deployed for real-time flexibility management to enable this. A 90% curtailment efficiency target by 2030 has been set, with outage planning tools optimised to use flexibility. The Day Ahead pilot outcomes strengthen the ED3 Load Strategy by demonstrating stakeholder confidence in flexibility markets as a credible, low-regret option for managing uncertainty. Flexibility is integrated into load optioneering but is not treated as a universal substitute for reinforcement due to delivery uncertainty. Reliance on community-scale flexibility as a baseline offset to reinforcement has been reduced, with flex included within optioneering as a supplementary, risk-managed input.
Supporting local economic growth, powering our communities and supporting Local Authorities	DSO Surveys (Keep in Touch), DSO Autumn Series (Webinars, Workshops, Roundtables), Connections Forums (DER, ICP/IDNO, Housing Developers), DNO Working Group on Community Energy, Consumer Priorities Research, Utility Week Virtual Roundtables ED3 Stakeholder Engagement Workshops, March 2026 (Perth, Reading & online deliberative workshops, independently facilitated): Session 1 - Planning for the ED3 price control; Session 2 - Transforming our approach to Low Voltage networks.	Local Authorities, Community Energy Groups, Housing Developers, Consultants, Distributed Generation Customers, ICPs/IDNOs, Domestic Consumers, SMEs, Academics, Industry Bodies	Stakeholders consistently called for coordinated, place-based planning with clear alignment between national, regional and local energy plans. Local Authorities want scenario tools, LAEP-ready data, and regular coordination on housing, EV/heat planning and renewables to support predictable, joined-up planning. Community energy groups emphasised the need for practical support, accessible tools, and clearer visibility of how their needs feed into SDPs, RESP and tRESP processes. There was strong consensus that community benefit and local value must be visible outcomes of network investment, with stakeholders wanting DSOs to act as coordinators and enablers rather than simply asset managers. Stakeholders also highlighted that customer engagement must be reframed in consumer-relevant terms, with benefits framed as outcomes such as 'EV-ready homes' and 'future-proof streets' rather than infrastructure language.	Stakeholder feedback has directly shaped the (ED3-S10) ED3 DSO Strategy by reinforcing the commitment to place-based, joined-up planning. LENZA and LAEP+ tooling developed in ED2 will be evolved into a fully integrated planning capability aligned to Regional Energy Strategic Planning (RESP) processes. The strategy establishes structured, ongoing engagement with NESO and regional stakeholders, producing coordinated, RESP-aligned planning outputs. A dedicated community energy coordination capability will be established to provide structured engagement, technical workshops and clear routes into SSEN's planning and connections processes. Working relationships with 72 Local Authorities are targeted by end of ED3 to ensure coordinated delivery. The strategy commits to co-developing Local Area Energy Plans with every local authority, aligning network investment with local net zero, housing, and economic development priorities.

Customer disruption and interruptions, coordination with other utilities and Local Authorities	Focus Groups (Consumer Priorities Qualitative), Online Forums (Housing Developer Forum, DER Forum, Equal LCT), Research (ENA Unlooping Research) ED3 Stakeholder Engagement Workshops, March 2026 (Perth, Reading & online deliberative workshops, independently facilitated): Session 2 - Transforming our approach to Low Voltage networks.	Housing Developers, Local Authorities, DER Operators, Consultants, Domestic Customers, Community Energy Groups, Other Utilities	85% of stakeholders want early visibility of LV upgrade programmes. Strong calls for coordination: stakeholders suggested facilitating easier easements, upgrading existing infrastructure alongside new works, collaborating with other network upgrades, coordinating with other utilities, and using directional drilling. Customers expect works to be done once, fairly, providing future-proofed benefits. DNOs are seen as the best-placed communicators (followed by LAs), which should note that acceptance increases significantly when mitigations are explained (advance notice, reinstatement standards). Customers prefer letters/leaflets backed by TV/social media for awareness.	Full visibility of forward programmes for all stakeholders committed by April 2030. Coordination with other parties embedded in programmatic approach and pilots. External IT investment for visibility of future work programmes via LAEP+(LENZA) tool providing street-level view of LCT forecasts and draft programme. Dedicated community liaison teams established to engage with stakeholders and support end-to-end customer journey. Customer engagement portal developed including knowledge library, Connections Readiness Indicator, and customer journey explanation.