SP Energy Networks
Draft Network Development Plan – for consultation
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SP ENERGY NETWORKS

Network Development Plan

Part 3 – Methodology Report

PRINCIPAL PARTNER
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1 Introduction

1.1 Who we are

We are SP Energy Networks. We own and operate the electricity distribution network in Central and Southern Scotland (our SP Distribution network), and in North Wales, Merseyside, Cheshire, and North Shropshire (our SP Manweb network). It is through these two networks of underground cables, overhead lines, and substations that we provide our 3.5 million customers with a safe, reliable, and efficient supply of electricity.

1.2 Document context and scope

Sharing data is key to the efficiency of the energy system as we decarbonize to Net Zero. It enables customers and stakeholders to assess market opportunities and participate in flexibility markets, in turn promoting the efficiency and competitiveness of these markets. It enables network companies and key stakeholders to work together to promote efficient whole system planning and operation. And it helps spur innovation and new solutions. Customers benefit from all of these.

In this context, Standard Licence Condition 25B came into force on 31 December 2020.[1] It introduced a requirement for each DNO to publish a Network Development Plan (NDP), and set out a high-level scope of what was to be included. DNOs then worked together via the Energy Networks Association to define the detailed scope and content of NDPs; the resulting proposed Form of Statement was published in December 2021.[2]

The primary objective of the NDP is to provide information on available network capacity to accommodate demand and generation growth, and interventions the DNO plans which will increase network capacity (such as flexibility use and reinforcement). The NDP is a medium-term outlook, and is designed to sit between short-term Long Term Development Statements (LTDS) and long-term Distribution Future Energy Scenarios (DFES) forecasts.

Each DNO's NDP must cover three main components:

1. **Part 1: Network development report** – detailed information on the interventions we plan that will increase capacity. This includes non-load interventions which are not done to provide capacity but will increase capacity nonetheless (e.g. asset management interventions such as replacing an end-of-life transformer with a larger equivalent).
2. **Part 2: Network capacity headroom report** – the indicative demand and generation capacity available at each primary substation (down to and including the HV busbar). Forecasts are produced for every year for the first 10 years, and then for every five years after that out to 2050. These capacity forecasts must take account of known planned interventions which will increase capacity (Part 1).
3. **Part 3: Methodology statement** – a document explaining how we have produced Parts 1 and 2.

Parts 1 and 2 need to be produced for each DNO licence area, down to primary substation group (i.e. the NDP does not include network interventions and capacity headroom for the LV and HV networks). We have two licence areas: SP Distribution and SP Manweb. Therefore to discharge our NDP licence obligation we are publishing four NDP documents[3]:

1. A summary document to introduce our NDP, summarise the contents, and set out our consultation questions.
2. A pdf report and supporting excel datasheet for SP Distribution, covering Parts 1 and 2.
3. A pdf report and supporting excel datasheet for SP Manweb, covering Parts 1 and 2.
4. A single document for Part 3, covering SP Manweb and SP Distribution together as the methodology is the same for each. That is this document.

[1] https://www.legislation.gov.uk/uksi/2020/1401/made/data.xht?view=snippet&wrap=true
[2] https://www.energynetworks.org/industry-hub/resource-library/on21-ws1b-p5-network-development-plan-(ndp)-form-of-statement-template-and-process-(22-dec-2021).pdf
[3] www.spenergynetworks.co.uk/NDP

Figure 1 shows the document map for these four documents.

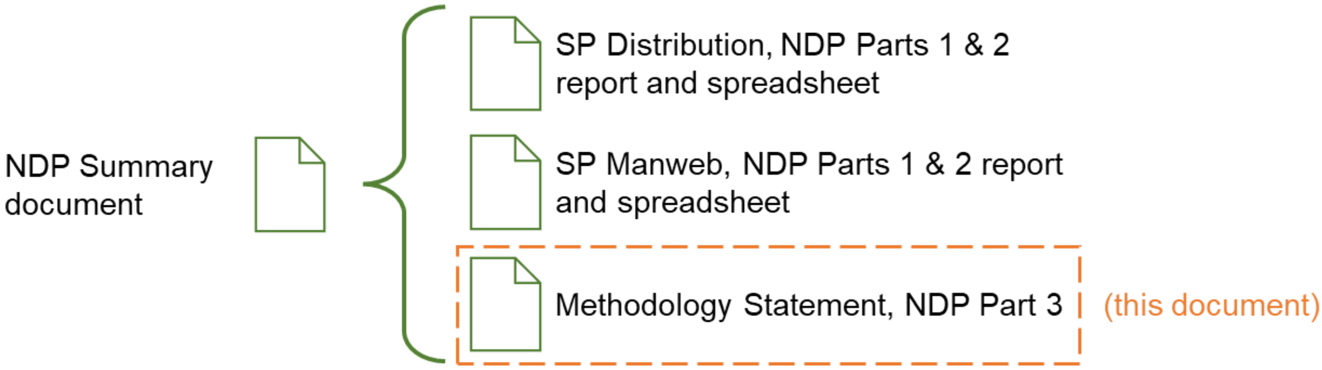


Figure 1: SP Energy Networks' NDP document map

1.3 Document structure and overarching process

This document is the NDP Part 3 Methodology Statement. It explains how we produced NDP Parts 1 and 2 for SP Distribution and SP Manweb. The structure of this document follows the overarching process we followed to produce our NDP:

- **Section 2 – Step 1, forecasting:** we develop our network to accommodate our customers' demand and generation requirements. Therefore the first step of network planning is to understand what these are. We do this using forecasts.
- **Section 3 – Step 2, network impact assessments:** we undertake industry-leading assessments to understand where, when, and how much additional network capacity is needed to accommodate these forecast customer requirements.
- **Section 4 – Step 3, flexibility tenders:** where our assessments show we need additional capacity, we tender for flexibility services to understand the availability and cost of using flexibility to provide it. We don't place contracts at this stage – we only do that where the Step 4 options assessments establish flexibility is the best solution.
- **Section 5 – Step 4, options assessment for load-driven investment:** to provide the capacity in the optimal way, we fairly and impartially assess different types and combinations of interventions (flexibility, energy efficiency, smart, innovation, and reinforcement), different delivery models (reactive, proactive), and how they could be coordinated with other interventions to reduce customer cost and disruption.

These four steps identify the RIIO-ED2 load interventions we will make that add network capacity – these are a key input to NDP Parts 1 and 2. Whilst these create the majority of the additional capacity we will deliver, the NDP requires that we include all interventions that increase capacity:

- **Section 6 – Step 5, NDP Part 1 – reporting of network interventions which add capacity:** we combine the load driven interventions identified in steps 1-4 with non-load and losses driven interventions which add capacity, to produce NDP Part 1.

After these five steps we know all the interventions we plan to make that will add capacity – this means Part 1 of the NDP is complete. To complete Part 2:

- **Section 7 – Step 6, NDP Part 2 – reporting network capacity headroom:** combining our existing network model, our scenario forecasts, and our known intervention plans to calculate the 'post-intervention' headroom. Our NDP Part 2 Capacity Headroom spreadsheet data files provide an indication of headroom for each primary (and grid in SPM) substation/substation group for each year for ten years and every 5 years through to 2050 thereafter.

We are aware that our industry includes a wide range of terminology, so **Section 8** is a glossary to explain the terms we use within our three NDP documents.

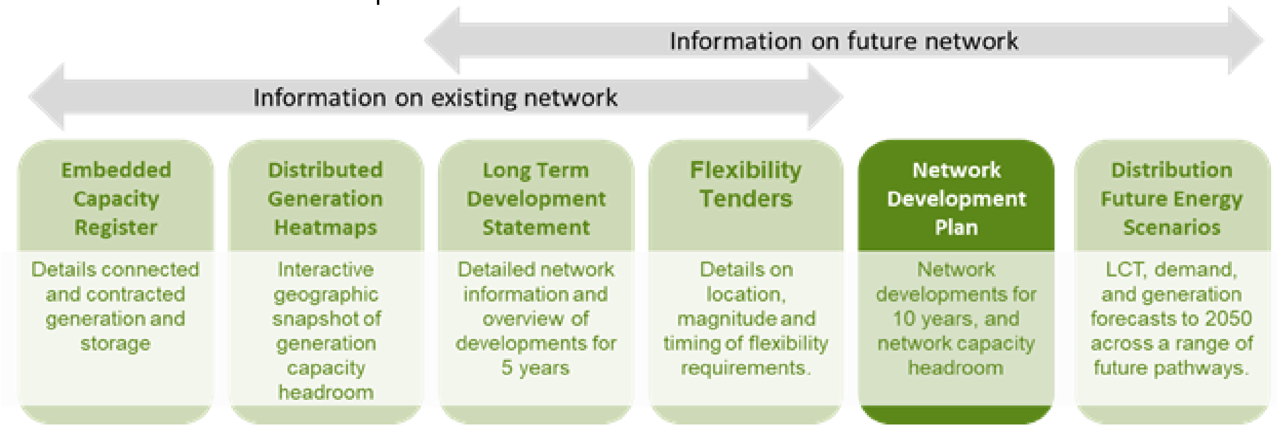
1.4 Next steps

Our three NDP documents are now out for consultation until **16 April 2022**. Given that the purpose of NDPs is to share information with stakeholders, it's important that these documents meet our stakeholders' needs. We therefore welcome stakeholder views. Consultation questions and details on how stakeholders can feedback are given in our NDP summary document.

The consultation period will close **16 April 2022**. We will then publish the finalised versions of our three NDP documents by 29 April 2022.

1.5 How the NDP fits with other data provision

Publishing our NDP is just one measure we're taking to increase the transparency of how we plan and operate our distribution network, and is aligned with our approach of sharing an increasing range of network data with stakeholders. Other current data provision includes:



- **DFES forecasts**[4] – these are forecasts for key customer demand and generation metrics up until 2050. We develop these considering a range of sources, including UK and devolved government targets and other industry forecasts. Given the uncertainties out to 2050, we create forecasts for four main energy scenarios. These scenarios represent differing levels of customer ambition, government and policy support, economic growth, and technology development. Our stakeholders review our forecasts and we make changes based on their well-justified feedback. We will update our DFES annually.
- **LTDS**[5] – these statements contain a range of information on our 132kV, 33kV, and 11kV network. This includes network asset technical data, network configuration, geographic plans, fault level information, demand and generation levels, and planned works. This information helps customers identify opportunities and carry out high level assessments of the capability of the network to accommodate new demand and generation. A main update is published every November with a minor update every May.
- **Embedded Capacity Register**[6] – previously known as the System Wide Resource Register, this currently provides information on generation and storage resources (≥1MW) that are connected, or accepted to connect, to our distribution network. It is updated on the 10th working day of each month.
- **Heatmaps**[7] – these provide a geographic view of where there is available network capacity to accommodate new generation.
- **Flexibility tenders**[8] – we tender for flexibility for all viable network constraints. When we run tenders we publish information on the location, magnitude, and duration of the constraint. In some cases we will also send ceiling price information. We run tenders twice annually.

Looking forward to RIIO-ED2, we plan to share a wider range of historical, near-time, real-time, and forecast data with stakeholders. This will be underpinned by infrastructure to gather, assess, and share data, and engagement with stakeholders to prioritise data publication. Please see our DSO Strategy[9] for more information on the network data we plan to share in RIIO-ED2 based on stakeholder input.

[4] Our DFES is available here: Distribution Future Energy Scenarios - SP Energy Networks
[5] Our LTDS is available here: Long Term Development Statement - SP Energy Networks
[6] Available here: Embedded Capacity Register - SP Energy Networks
[7] Our heatmaps are available here: Distributed Generation Heat Maps - SP Energy Networks
[8] Available here: Flexibility Services - SP Energy Networks
[9] Our DSO Strategy is Annex 4A.3 of our RIIO-ED2 Business Plan. Available at: https://www.spenergynetworks.co.uk/userfiles/file/Annex 4A.3 - DSO Strategy .pdf

1.6 How the NDP overlaps with our RIIO-ED2 Business Plan

The NDP requires us to publish our planned interventions which will increase network capacity, and the resulting network capacity headroom. This first NDP comes a few months after we published our RIIO-ED2 Business Plan[10] on 1 December 2021. There is significant overlap between the two publications: the work we need to do to produce the NDP is the same that was done to create our RIIO-ED2 Business Plan, and all the EHV and 132kV interventions that increase capacity that we included in our RIIO-ED2 Business Plan need to be included within the NDP. So where our suite of NDP documents refers to RIIO-ED2 interventions and the RIIO-ED2 process, it is because they are directly relevant to the NDP.

Providing capacity (the scope of the NDP) is only one part of planning and developing a network. This means the interventions covered in our NDP are only a subset of those we need to make through RIIO-ED2. For a good summary overview of the full range of measures we're taking to ensure we have a safe, reliable, and efficient network, please see our Future System Strategy.[11]

[10] Our RIIO-ED2 Business Plan is available at: https://www.spenergynetworks.co.uk/userfiles/file/SPEN%20RIIO-ED2%20Final%20Business%20Plan%20-%201st%20December%202021%20-%20FINAL.pdf
[11] Our Future System Strategy is Annex 4A.1 of our RIIO-ED2 Business Plan. Available at: https://www.spenergynetworks.co.uk/userfiles/file/Annex%204A.1%20-%20Future%20System%20Strategy.pdf

2 Forecasting our customers' needs

We develop our network to accommodate our customers' requirements. Therefore the first step of network development planning is to understand what these are. We do this using forecasts. We start by creating DFES forecasts, and then compare these to Climate Change Committee (CCC) and Electricity System Operator Future Energy Scenario (ESO FES) forecasts to create investment scenarios. These investment scenarios are the foundation on which we build our network development plans.

2.1 DFES forecasts

These are forecasts for a range of customer demand and generation metrics up until 2050. We develop these considering a range of sources, including UK and devolved government targets such as: Net Zero targets of 2045 for Scotland and 2050 for England and Wales; interim legislative 2030 and 2035 greenhouse gas emission reduction targets; Scottish and UK government bans on new petrol and diesel cars and vans; the UK Government Ten Point Plan, Energy White Paper, and Heat and Buildings Strategy; and the Scottish Government Heat in Buildings Strategy; and the Net Zero Wales Plan. Our stakeholders review our forecasts, and we make changes based on their well-justified feedback, to create regionally reflective, granular forecasts.

Given the uncertainties out to 2050, we create forecasts for multiple energy scenarios. These scenarios represent differing levels of customer ambition, government and policy support, economic growth, and technology development. Our stakeholders review our forecasts and we make changes based on their well-justified feedback.

The process to create our DFES can be summarised as:

- **DFES Step 1: scenario definition**. We develop our DFES in line with the approach agreed in the Energy Networks Association's (ENA) Open Networks project. Our DFES uses the same scenario framework as in the ESO FES.
- **DFES Step 2: baseline data**. We use a combination of our network data and other sources of data to determine the starting position for our forecasts. This includes historical demand trends, measured demand, connections data, EV and heat pump notifications, and other external sources of data to validate the accuracy of our information (for example Department for Transport EV registrations, Ofgem Feed-in-Tariff data etc.).
- **DFES Step 3: analysis of regional factors**. We use the ESO FES as a starting point for our DFES forecasts. However, the FES is not detailed enough for our requirements, so we significantly augment it to capture regional requirements and provide a much more granular view. This is done using a combination of top-down and bottom-up assessments, stakeholder feedback, devolved government policy and plans, regional development plans, accepted connection requests and other regional data.
- **DFES Step 4: forecast outputs**. We produce forecasts for individual demand and generation metrics, for example EV uptake and solar photovoltaic (PV) capacity. These key metrics are forecast for each scenario at a GSP and primary substation geographic level, and for each year out to 2050.
- **DFES Step 5: draft publication**. We created a suite of documents to explain our forecasts, given that different stakeholders require differing levels of detail. These are all available on our DFES website.
- **DFES Step 6 & 7: stakeholder testing and updates**. We test our forecasts with informed stakeholders. We look at the underlying assumptions of each key DFES metric (e.g. EV, HP) and adjust them based on stakeholder feedback where we had sufficient evidence to do so. We only make regional adjustments to the underlying FES scenarios where these are well-justified.
- **DFES Step 8: publication**. Our updated DFES documents and data tables are published, including the stakeholder feedback we received and if/how used that to update our forecasts.

For more details on UK, Scottish, and Welsh Net Zero targets and the DFES forecasting methodology, scenario assumptions, stakeholder feedback, data workbooks and maps, please see our DFES suite of documents available on our DFES website[12].

[12] www.spenergynetworks.co.uk/dfes

2.2 Converting forecasts into investment scenarios

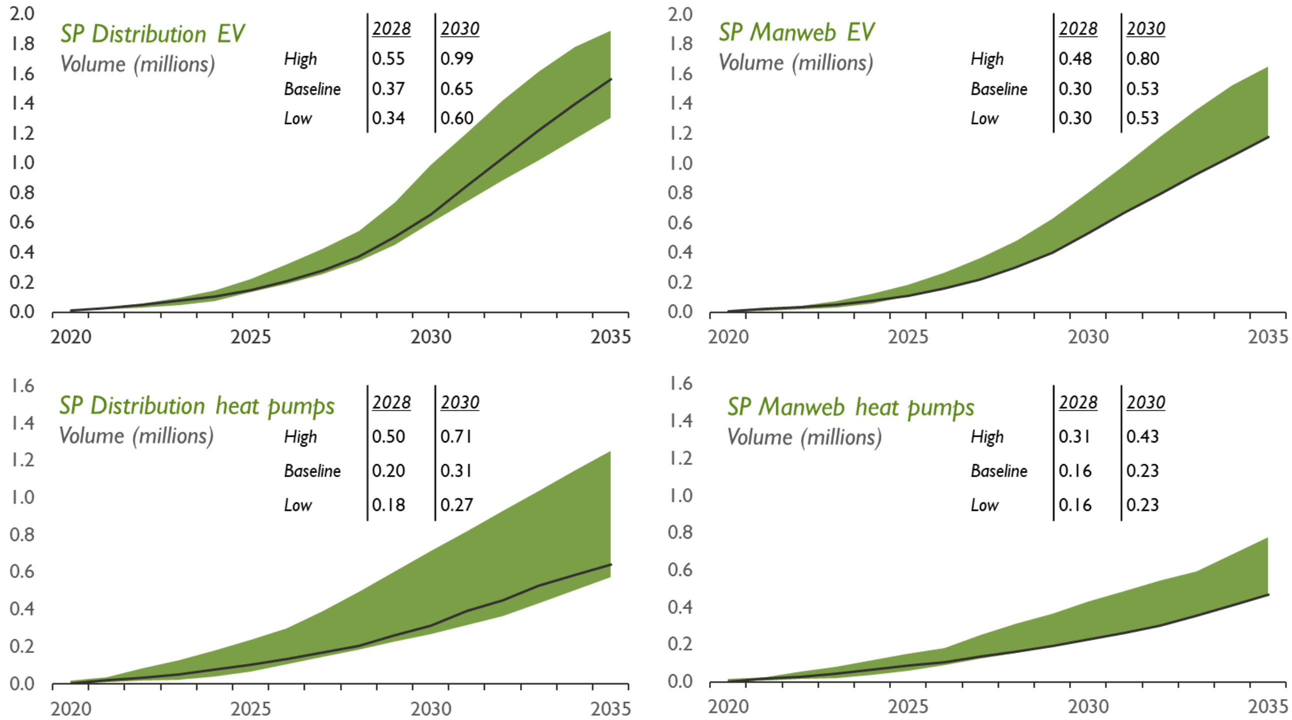
The four DFES forecast scenarios will have different network impacts, requiring different levels of investment. So how do we know which one to plan for? In addition to the four DFES scenarios, we create a low scenario, a baseline scenario, and a high investment scenario. Our RIIO-ED2 investment plan is developed to deliver the baseline scenario, but must have the adaptability to deliver anywhere within the low and high scenario range (which mark the lower and upper range of credible Net Zero pathways).

These three scenarios were developed considering the range of Net Zero compliant scenarios developed by us, the ESO[13], and the CCC[14]. We only consider Net Zero compliant scenarios as Net Zero is mandatory with relevant legislated targets applied across the UK. This means we discounted two DFES and FES scenarios:

1. Steady Progression (SP): this scenario does not meet Net Zero and so has been excluded.
2. System Transformation (ST): we consider this scenario is unable to meet Scottish Government legislative targets or UK interim emission reduction targets, and so has been excluded.

The remaining two DFES scenarios, two FES scenarios, and five CCC scenarios collectively form the Net Zero compliant scenario range and so determine our low and high scenario. This range of scenarios meets UK and Scottish Net Zero legislation; the requirements of the UK Government's Ten-Point Plan, Energy White Paper, and Heat and Buildings Strategy; the Scottish Government's Update to the Climate Change Plan and Heat in Buildings Strategy; and the Net Zero Wales Plan.

Within this low to high scenario range we selected our baseline scenario. The baseline scenario represents the best approach for our customers assuming the appropriate regulatory mechanisms are in place. Figure 2 shows the low, baseline, and high scenarios for EVs and heat pumps out to 2035 for each licence area (the black line is our baseline scenario, the green band marks the low and high scenario range).



SP Distribution EV

	2028	2030
High	0.55	0.99
Baseline	0.37	0.65
Low	0.34	0.60

SP Manweb EV

	2028	2030
High	0.48	0.80
Baseline	0.30	0.53
Low	0.30	0.53

SP Distribution heat pumps

	2028	2030
High	0.50	0.71
Baseline	0.20	0.31
Low	0.18	0.27

SP Manweb heat pumps

	2028	2030
High	0.31	0.43
Baseline	0.16	0.23
Low	0.16	0.23

Figure 2: Our RIIO-ED2 baseline scenario compared to Net Zero compliant industry forecasts

Figure 2 shows that our baseline scenario tracks the bottom of the credible range in SP Manweb, and marginally above in SP Distribution due to Scottish Government targets. This is intentional. By basing our investment plan on the lower end of Net Zero compliant forecasts, we're confident that we are only asking for the minimum investment needed to enable Net Zero, as actual EV and heat pump uptake is unlikely to be lower

[13] The Electricity System Operator's '2021 Future Energy Scenarios', published July 2021. Available at: https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021
[14] The Climate Change Committee's 'Sixth Carbon Budget', published December 2020. Available at: https://www.theccc.org.uk/publication/sixth-carbon-budget/

than this baseline scenario. Where actual levels are higher than this baseline scenario, our plan can adapt across to address the difference providing agile uncertainty mechanisms are in place.

This approach and the use of uncertainty mechanisms means we have a robust investment plan which can adapt to our customers' needs across the range of credible Net Zero pathways, and it protects customers by making sure we have sufficient investment to enable Net Zero but no excess allowances.

Please see our RIIO-ED2 Load Related Expenditure Strategy (Annex 4A.2 of our RIIO-ED2 Business Plan) if you would like more information on how we created our investment scenarios and set the baseline scenario.

2.3 Using innovation to take our forecasting further

DFES, CCC, and ESO forecasts are wide-area macro forecasts. To develop our load-related intervention plan, we need to understand what is happening at a much more locationally granular level. This is especially important for domestic EV chargers and heat pumps, as they are the two main drivers of increasing network demand.

In response, we've developed two enhanced forecasting tools built on successful innovation projects. They're called EV-UP and Heat-Up, and they use spatial, demographic, and socioeconomic data to forecast EV and heat pump uptake for every customer we serve. We are the only DNO to do this.

They are complementary to our low, baseline, and high scenario forecasts. The scenarios consider a range of macro factors (such as legislation and technology development) to forecast total EV and heat pump volumes across our whole licence area. EV-Up and Heat-Up show, for any scenario, how these are likely to roll-out across the network – they show us which individual households will get them and in what timescales (Figure 3).

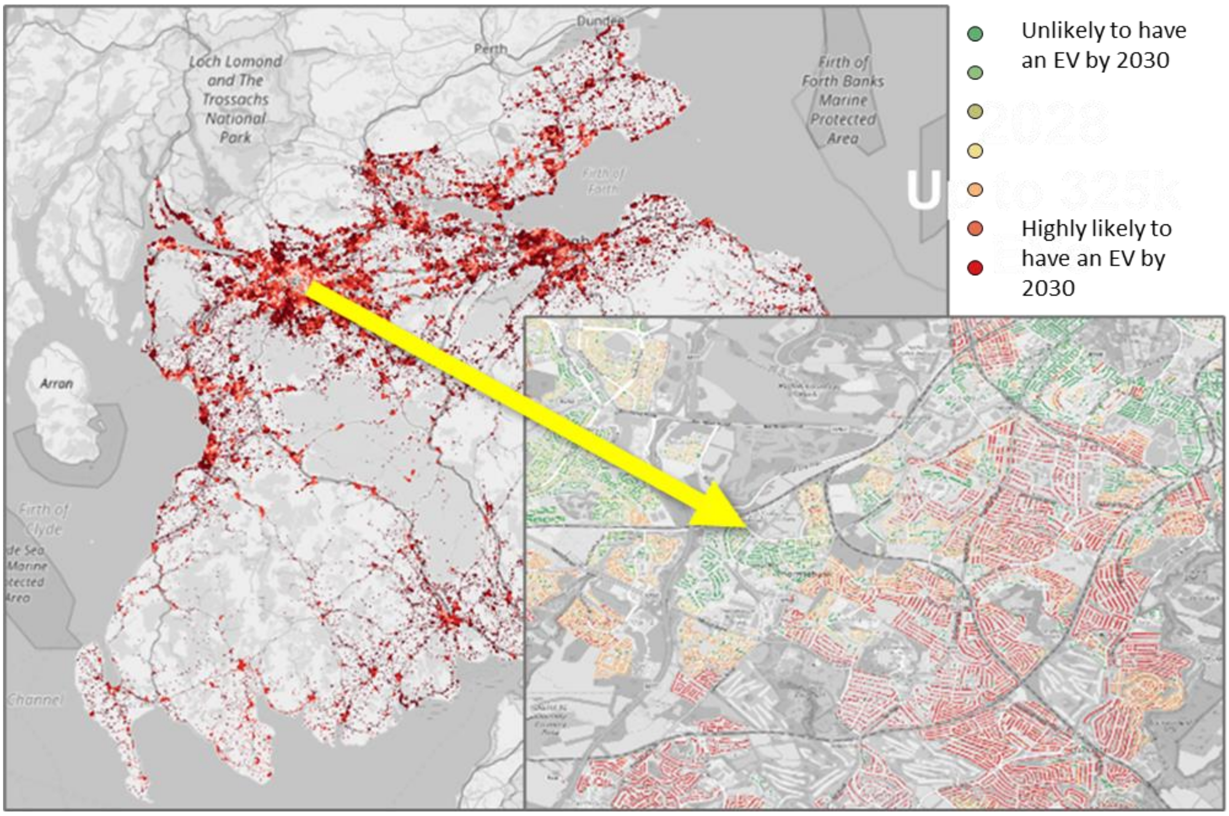


Figure 3: EV-Up forecast maps

This information is then added to our new Engineering Net Zero (ENZ) Model, where we can overlay EV and heat pump uptake on our network asset database and run power flow analysis to identify network constraints – Section 3 explains this process. This lets us identify where any network impact will occur more precisely than current methods have allowed us to.

These enhanced forecasting insights have helped us identify precisely where and when we need to invest. This benefits our customers as we've been able to develop a targeted and efficient RIIO-ED2 intervention plan to accommodate their requirements.

EV-Up and Heat-Up are just two of a number of enhanced forecasting tools we've developed in RIIO-ED1 that will deliver benefits for customers in RIIO-ED2 and beyond. Our CHARGE project combines transport modelling and network planning to advise local authorities where to optimally site public EV chargers, and our Weather Normalised Demand Analytics (WaNDA) tool models weather effects on network power flows. We've also developed a near-time forecasting platform to give demand and generation forecasts for up to four days ahead. We use this to plan our utilisation of operational measures such as service providers.

Please see our RIIO-ED2 Load Related Expenditure Strategy (Annex 4A.2 of our RIIO-ED2 Business Plan) if you would like more information on our forecasting tools.

3 Network impact assessments

Forecasting → **Network assessments** → Flexibility tenders → Options assessments → Intervention plan (NDP Part 1) → Capacity Headroom (NDP Part 2)

Our forecasts show that customer demand and generation levels are increasing significantly. This section explains how we assessed the ability of the existing network to accommodate these changes, and how we identified where, when, and how much additional network capacity we need to provide. We use this information to then tender for flexibility (Section 4) and identify the interventions we need to make (Section 5).

3.1 Our ENZ Model

The level of activity on our distribution networks is a step change from decades of steady, predictable, incremental change. We need to do more than just increase network capacity – to enable us to fully understand the network impact of our future energy scenarios and intervention requirements at an individual asset level we have needed to significantly develop our modelling capability.

Therefore over RIIO-ED1, through our award-winning Network Constraints Early Warning System (NCEWS) innovation project, we have built a full connectivity model of all 48,000km of our LV network. We've combined it with our existing HV and EHV network connectivity models, so we now have a complete model of our entire network, from customers' cut outs up to the transmission network. We call this our ENZ Model.

The ENZ Model allows for complex modelling and is a significant advancement on vectorised geographic information systems (GIS). It has been designed to operate with large data sets and provides access to full asset data including conductor types, ratings etc. It enables us to trace the network and aggregate demand, including the effects of demand diversity at any point in the network. These developments are part of our efforts to enable better monitoring, control, design, and operation of the network.

3.2 Using our ENZ Model to develop intervention plans

We used our ENZ Model to develop our load intervention plan. Using outputs from our DFES, our low, baseline, and high scenarios, and enhanced forecasting tools (Section 2.3), the ENZ Platform ran a comprehensive programme of power flow analysis for every half hour for every forecast scenario – 175,000 iterations per network asset. This systematically identified the location, magnitude, and timing of every network constraint in RIIO-ED2 (Figure 4).

Figure 4: ENZ Model

The process in detail was as follows:

- **Step 1: assessing present maximum loading for each asset.** At primary substation (EHV/HV) and above, the historical network SCADA network data was fully available. At lower voltages, the present loading was assessed using the full connectivity data including the number, type, and size of customers supplied by each asset. This assessment made use of utilisation data where this was available, for example using Maximum Demand Indication (MDI) data.
- **Step 2: assessing the forecast change in loading for every asset.** The ENZ Model used the low, baseline and high scenario forecasts, including the individual property level data from EV-Up and Heat-Up across the entire network. The modelling combines the forecast information with detailed network data on each of the assets (e.g. their electrical characteristics, ratings etc.) to calculate the change in asset loading.
- **Step 3: identifying and characterising forecast capacity constraints.** The ENZ Model established what the resulting loading would be for each scenario and identified where individual assets would be operating outside network limits. This is where network constraints would occur if we do not deliver additional capacity. In many cases to understand these constraints better we modelled constraints for every half hour period, at individual asset level, for both normal and fault conditions, in each year up to and beyond 2030.

After this process we know the timing, location, type (e.g. thermal, voltage), and magnitude of every forecast constraint in RIIO-ED2.

To put this level of analysis into context, each iteration of the model required around 20 hours of processing time using high-powered cloud-based Microsoft Azure virtual servers. It processed over 150k circuits and 70k transformers in each scenario. Traditional manual modelling would not have been capable on this level of analysis. The model can be viewed geographically to see which customer properties are likely to have EV and heat pumps and which assets will overload as a result.

How we use the modelling outputs

We assessed the range of low, baseline, and high scenarios to systematically identify where, when, and how much additional capacity is needed to accommodate customer needs. This fed into flexibility tender requirements and outlined the minimum requirements that conventional / smart solutions would need to be capable of managing. This information is a key input for the flexibility tendering and solution options assessments stages (Sections 4 and 5 respectively).

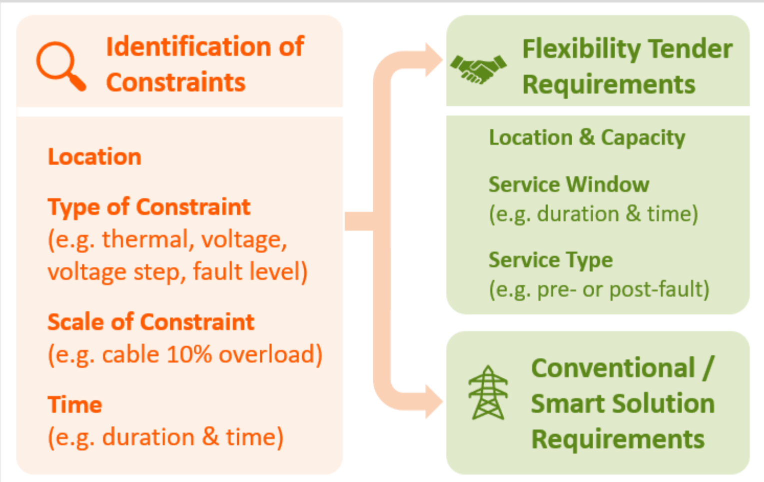


Figure 5: Outputs of the network impact assessments

If we have a single baseline forecast scenario, why model the other forecast scenarios?

Modelling the low to high scenario range in addition to the Baseline scenario helps us in the following ways:

- Seeing the results from the range of scenarios helps us identify sensitivities. These may then need to be investigated further, or managed through the RIIO mechanism.
- Some areas of the network will be constrained in all scenarios. This helps prioritise interventions – constraints that appear in all scenarios are usually those that are closest to manifesting.
- The highest impact scenario represents our upper case. This helps us understand what we need to be prepared to potentially deliver.

What are the different types of network constraint and when do we intervene?

There are three main types of network constraint. These are:

1. **Thermal constraints** – where network current would exceed equipment thermal ratings. Thermal constraints can affect any type of asset at any voltage level. High loadings on certain assets may simply reduce their life, however significant overloading introduces safety risk. For example, an overhead line conductor will sag more if it is overloaded – this may risk the statutory minimum safety clearance distances outlined in the Electricity Safety, Quality and Continuity Regulations (ESQCR).

   The thermal loading on each asset is considered against its capability under normal and fault/outage conditions. Equipment thermal ratings are considered to vary seasonally with temperature through the year. Cyclic thermal ratings of assets are used when assessing the network under fault/outage conditions. The cumulative time exposure to overloads, and whether equipment has sufficient cool back periods are considered. We prioritise interventions when the network assets are at risk of exceeding 100% of their thermal rating.
2. **Voltage constraints** – where network voltage would be in breach of statutory limits. Network voltages can be too low (usually caused by excess demand), too high (usually caused by excess generation), or change too quickly (instantaneous change in voltage due to planned/unplanned outages). Voltage excursions can cause damage to customer equipment and network assets, and introduce safety risks.

   We have a duty to maintain voltages within the statutory limits at each voltage level. We prioritise interventions when the network is at risk of breaching these limits.
3. **Fault current constraints** – where the network fault current would exceed the fault current rating of switchgear. If this happened, it would represent a serious safety risk as the network could not be safely isolated in the event of a fault. Fault current constraints can affect equipment at any voltage level.

   Circuit breakers may be called upon to disconnect faulting equipment from the network; or energise onto faulty or earthed equipment. Different types of fault (including 3-phase and single-phase faults) are assessed under make and break fault duties. Where substations are approaching switchgear capability or operationally managed, detailed assessments of the maximum fault flows through each individual breaker are undertaken. Substation infrastructure such as busbars, supporting structures, flexible connections, current transformers, and terminations must be capable of withstanding the mechanical forces associated with the passage of high magnitude fault current i.e. through-current withstand duty. Where switchgear is in excess of 95% of equipment or design rating we consider the substation to be constrained.

These constraints can occur together or independently. These network constraints are a result of there being insufficient network capacity to accommodate customer power flows and demand/generation growth.

4 Flexibility tenders

Forecasting → Network assessments → **Flexibility tenders** → Options assessments → Intervention plan (NDP Part 1) → Capacity Headroom (NDP Part 2)

We tender for flexibility tenders as standard for all viable[15] network constraints. This helps us understand the availability and cost of flexibility – we use this information for the subsequent solution options assessments step (Section 5).

4.1 Flexibility services

Flexibility services are where our customers agree to actively manage their demand or generation to help us manage capacity constraints on our network. Flexibility services can help us defer or avoid new network capacity, can be deployed more quickly than reinforcement interventions, and can help democratise and bring competition to the energy sector. They provide an agile smart means of managing our network, and are complementary to reinforcement solutions by providing short-term solutions where we need to act quickly or manage uncertainty. They will play a key part in helping to manage the pace of the Net Zero transition.

We were the first DNO to tender for reactive power services and the first to tender with site-specific pricing.

4.2 Flexibility tenders

We tender for flexibility for all viable network constraints. When we tender for flexibility we state the location, service product (see Table 1), service window and time (e.g. 4-6pm weeknights between October and March), required magnitude (MW/MVArs), and any other necessary technical parameters (e.g. response time). In some cases we will also send ceiling price information.

Product	Timeframe	Flexibility product description
Sustain	**Pre-fault** *Scheduled*	• Sustain will be scheduled in advance of the service window to support security of supply during system intact conditions. • Utilisation fee payable for the service provided in response to the scheduled notice. • No availability fee payable.
Secure	**Pre-fault** *Scheduled or dispatched*	• Secure can be dispatched or scheduled to manage peak loading on the network and pre-emptively reduce network loading. • Utilisation fee payable for the service provided in response to the scheduled notice. • Arming fee is payable.
Dynamic	**Post-fault** *Dispatched*	• Used to support the network in the event of specific fault conditions. • Providers declare availability one week ahead. • Dispatch instruction issued if service is required. • Utilisation fee payable if service is provided. • Availability fee is payable once availability has been accepted.
Restore	**Post-fault** *Dispatched*	• Used to help with restoration following rare fault conditions. • Providers declare availability one week ahead and declarations automatically accepted. • Dispatch instruction if service is required following a network event. • Utilisation fee payable for the service provided.
Reactive Power *(aligned with Secure)*	**Pre-fault** *Scheduled or dispatched*	• Reactive power can be dispatched or scheduled to support the management of voltage constraints. • Utilisation fee payable for the service provided in response to the scheduled notice. • Arming fee is payable.

Table 1: Flexibility products

[15] For example, flexibility can't resolve fault level constraints so we won't tender for flexibility for those types of constraints.

Once we receive tender responses, the bids are assessed in detail to check they were in the right area of network and could technically manage the constraint. We assess any risks associated with using the flexibility and considered the most cost-efficient mix of tender responses (if responses were greater than requested capacity). Technically competent bids feed into our options assessments (step 4 / Section 5) where they are assessed alongside all other options. We publish the results of our tenders, which includes prices bid and reasons for acceptance/rejection. Where we receive no acceptable bids, we may retender for the same constraint in a future tender round. Please see Appendix A for some examples of where we use flexibility on our EHV and 132kV network.

The capacity headroom data presented in this report incorporates flexibility services where contracts have been awarded.

4.3 Our twice-annual flexibility tendering process

We plan initially to run these competitive flexibility tenders twice a year (spring and autumn). This timetable, along with documents detailing our flexibility processes are published online.[16]

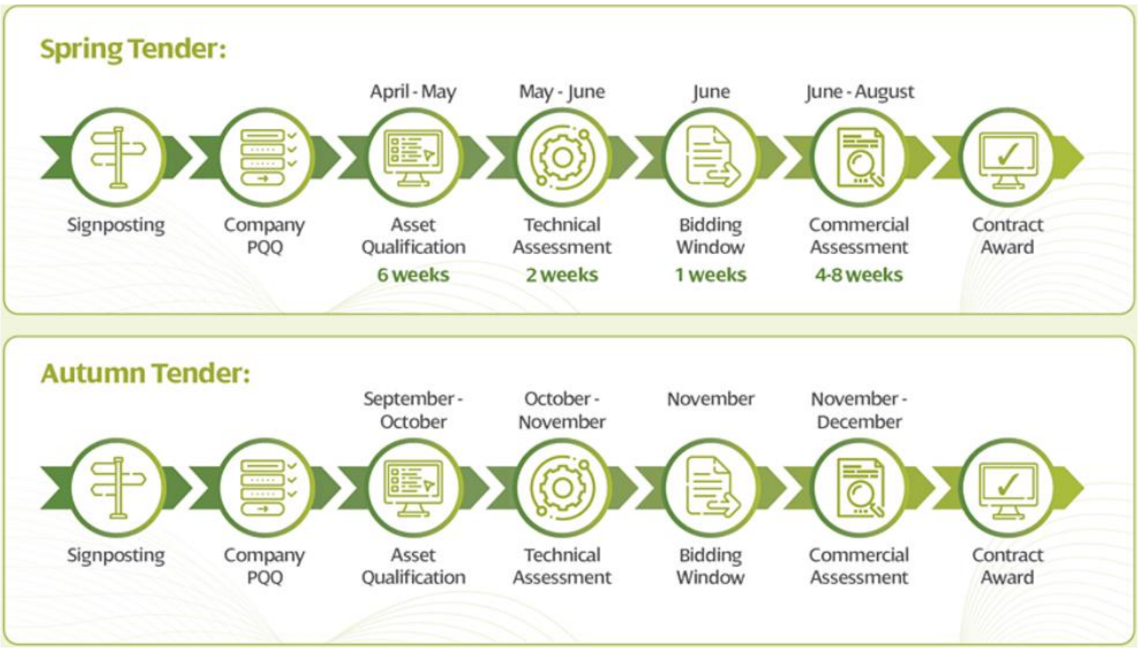


Figure 6: Annual Flexibility Tender process timeline

In the longer term, to manage the levels of uncertainty implicit in the journey to Net Zero and as the liquidity of the flexibility market increases, we expect that we will move to more frequent flexibility procurement. Ultimately this may lead to a market similar to the GB ESO Balancing Market where we can procure services in near real-time. This will need to be supported by adequate systems and skills to manage real time service procurement, dispatch, and settlement.

4.4 Additional considerations when using flexibility to manage constraints

When using flexibility to manage constraints there are additional network considerations which we must consider. For example, flexibility services are not able to manage all types of constraints and must be balanced with increased network risks. Higher risk constraints are difficult to offset using flexibility.

We consider the increased risk/likelihood of a capacity shortfall. For example, considering scenarios where individual service providers do not deliver the contracted level of service at a time the network requires them. In some circumstances it may be appropriate to over-procure to reduce risk of reliance on individual service providers.

Flexibility contracts have a 90-day notice period compared with reinforcement at higher voltages which can have lead-times of over five years. Reinforcement decisions need to be made years in advance of need due to long-lead times.

We consider the resulting impact of flexibility capacity shortfalls. The impact of capacity shortfalls can vary significantly. For example, the impact of overloading a transformer could be quite different to that of an overhead-line where the increased sag could risk safety clearance distances. If flexibility were to be used to

[16] Available at: https://www.flexiblepower.co.uk/

offset constraints that could otherwise result in cascade tripping of large areas of network, then shortfalls in flexibility capacity could risk the supplies to these areas – potentially 10,000s of customers.

There are also other impacts that we are continuing to consider, including the environmental impact of using large amounts of dispatchable fossil-fuel generation to offset network risk.

5 Options assessment for load-driven investment

Forecasting | Network assessments | Flexibility tenders | **Options assessments** | Intervention plan (NDP Part 1) | Capacity Headroom (NDP Part 2)

By this point we know where, when, and how much additional capacity our customers need (Section 3) and the cost and availability of flexibility services (Section 4). This step now assesses all viable solutions (flexibility, energy efficiency, smart, innovative, reinforcement) on an equal and impartial basis to identify what interventions to use for each constraint and how to deliver them in the most efficient way – this step identifies the interventions we will deliver to provide the capacity our customers need.

5.1 Intervention options

For each forecast capacity need in RIIO-ED2, we assessed a range of flexible, smart, innovative, and conventional solutions. Table 2 shows the six main categories of interventions to add capacity. They are not mutually exclusive, so can be combined to provide capacity.

Intervention type	Advantages and disadvantages
Flexibility services Where customers agree to actively manage their demand/generation to help avoid constraints.	✓ Can help defer or avoid reinforcements ✓ Encourages competition and the democratisation of the energy system × Not always available as an option × Doesn't help fault level (switchgear) constraints
Energy efficiency Where customers have agreed to passive measures to manage their demand to help avoid constraints.	✓ Directly benefits the customer through lower bills ✓ Helps reduce whole system peak, network losses, and the need for generation capacity × Cost effectiveness (MW reduction per £) is lower than other solutions × Doesn't help fault level (switchgear) constraints
Smart network interventions Where we look to get more out of existing network capacity.	✓ Often lower-cost than network reinforcement ✓ Can have secondary benefits, such as enhancing the effectiveness of other interventions × Can increase network complexity × Typically lower capacity release than network reinforcement
Network reconfiguration Where we temporarily or permanently adjust the topography of the network to match existing network capacity with customer power flows.	✓ A low-cost intervention ✓ Quick to implement × Limited to where there is a low coincidence of customer usage between neighbouring sections of network
Enhanced asset ratings Where we seek to increase the thermal capacity of individual existing network assets without having to replace them.	✓ Typically a low-cost intervention ✓ Quick to implement × Capacity uplift might only be for short periods × Can increase asset deterioration × Doesn't help switchgear constraints
Network reinforcement Where we permanently increase network capacity by replacing existing assets or adding more assets – for example, a new substation.	✓ Allows significant customer demand and generation growth by providing substantial additional capacity ✓ Enables customer participation in wider market opportunities by providing unconstrained access on an enduring basis ✓ Can improve asset health and reliability × Can take a long time to deliver, especially if planning permission is needed × Potentially higher environmental impact than other interventions

Table 2: Network intervention categories

Included in the above are new solutions we've developed through RIIO-ED1 innovation projects which have been incorporated as business as usual solutions in RIIO-ED2 – please see the case study below for one such example. Building on RIIO-ED1 innovation has saved our customers over £80m across our whole business plan.

Case study: innovative approaches to managing fault level

In RIIO-ED1, we partnered with Outram Research Ltd to develop the world's first real-time fault level monitor. For the first time for any DNO, this gives an accurate real-time understanding of network fault level. We combined this innovation with a network management scheme – another first for any DNO. Together, these capabilities allow us to safely connect more generation without triggering fault level reinforcements.

This is good for our generation customers, who can connect more quickly and at lower cost. It's also beneficial for our wider customer base, who pay a portion of interventions to manage fault level.

Due to these advantages, we have included this system in our plans to manage 38 fault level constrained sites over RIIO-ED2.

5.2 Options assessments

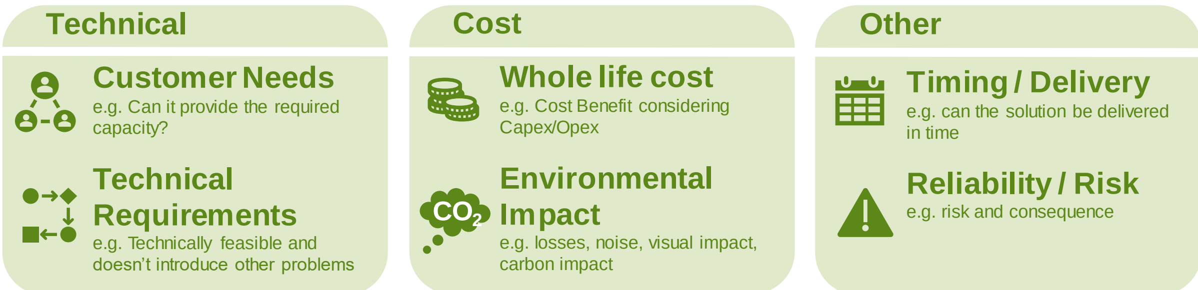
Having identified where, when, and how much additional capacity we need across our network in RIIO-ED2 (Section 3) and established the long-list of potential solutions (Section 5.1) including the availability of flexibility (Section 4), we need to identify the optimal combination and sequence of solutions for every constraint.

5.2.1 The information we need to assess solutions

To assess solutions we need to understand their costs and capabilities. For most solutions we do this by maintaining close links with manufacturers and industry, delivering innovation projects, monitoring other DNOs' innovation projects, and using our experience. To understand the costs and capabilities of flexibility services, we tendered for every forecast constraint that our load related plan is seeking investment to address (Section 4).

5.2.2 Overarching assessment criteria – the principles

When we assess interventions, we consider potential solutions against a number of factors:



1. **Does it provide the required volume of capacity in the right location?** If a solution can't provide sufficient customer capacity by itself, we will consider whether it can in combination with another solution.
2. **Is it deliverable in the timescales required by customers?** For example, a lengthy planning permission process may mean a particular solution cannot be delivered in the timescales required.
3. **Is it technically acceptable? Does it comply with technical standards and statutory limits?** For example, a solution may provide sufficient thermal capacity, but if it causes voltage levels to exceed statutory limits then it is not an acceptable solution.
4. **What is the whole life cost of the solution?** Here we consider both the upfront capital cost (capex) and the ongoing operational cost (opex).

5. **What is its environmental impact?** Here we consider the solution's impact on network losses, noise, visual impact, and carbon footprint.
6. **How does it align with our customers' priorities?** For example, our customer engagement shows that our customers' highly value a reliable supply so we will favour solutions which support this.
7. **Whole systems considerations?** Here we consider whether solutions are coordinated from a whole energy system perspective, or whether we need to engage with other stakeholders, for example the TO / adjacent DNOs.

We use these criteria to do a comparative assessment of the solutions – we know we need to intervene, so it's about establishing which solution is best. These criteria help identify the solutions we plan to use to alleviate network constraints and accommodate customer needs.

5.2.3 Assessment approaches at EHV and above

When assessing what solutions to use for each constraint, there are numerous variables to consider. For example, how our customers' capacity needs vary over time, how much capacity each solution adds, the lifetime of each solution, and the different capital (capex) and operational (opex) costs for each solution. This means there are a number of different combinations and sequences of solutions for each of the forecast RIIO-ED2 constraints, and we need to identify the individual optimal intervention approach for each.

We use detailed design studies, technical assessments, and CBAs for each scheme intervention at EHV and 132kV. These tools are excellent at analysing assessment criteria 1, 3, and 4 from the list above, but don't have the ability to assess other criteria such as deliverability. This means we use these tools to support the assessment criteria, rather than instead of them.

For each solution, we also consider how the potential requirements for the solution change across the low to high scenario range. This considers how robust the investment is across the range of credible Net Zero pathways, and identifies where the scope, magnitude, or timing of the investment is sensitive to the range of future pathways. Figure 7 shows an example of this: our plan is developed to deliver the baseline scenario (top row), meaning our plan contains a 7.5MVAr statcom delivered by 2028. However understanding how the solution varies across the main Net Zero decarbonisation pathways is helpful as the Figure 7 analysis shows us that:

1. a statcom is the right solution for every pathway, so we can be confident installing a statcom is a robust choice across different decarbonisation pathways.
2. the size of the statcom (7.5MVAr or 10MVAr) and the timing of when it's needed (2027-2029) is sensitive to the different decarbonisation pathways, so in the early years of RIIO-ED2 we need to monitor the situation and, if customer growth is higher than our baseline scenario, be prepared to install a larger statcom sooner than in our baseline plan. The additional funding needed for the larger statcom would need to be recovered through an uncertainty mechanism.

	RIIO-ED1				RIIO-ED2					RIIO-ED3				
Solution Requirements	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Baseline									S1					
Consumer Transformation								S2						
Leading the Way									S1					
Balanced Net Zero Pathway									S1					
Headwinds										S1				
Widespread Engagement								S2						
Widespread Innovation								S2						
Tailwinds									S1					

S1 – Install +/-7.5MVAr STATCOM at Stranraer

S2 – Install +/-10MVAr STATCOM at Stranraer

Figure 7: Example of solution sensitivity to future pathways assessments

Using this approach, we have built up a bespoke and robust set of interventions for every scheme at EHV and above. For each scheme, we have summarised the investment into ex ante baseline funding, and uncertain funding associated with the higher uptakes.

5.3 Assurance process

As part of our process to prepare our RIIO-ED2 business plan, we produced Engineering Justification Papers (EJPs) for 100% of the Load expenditure included in this NDP. These have all been assured through our internal governance group and all systematically reviewed by external experts S&C Electric (their review was led by an ex-Ofgem Costs and Outputs team lead). S&C's final report found that 100% of our EJPs achieved a 'green' assessment on aggregate.

This means every £ of load expenditure included in this NDP has been externally assured and approved. This 100% assurance is well over and above Business Plan Guidance requirements and gives confidence to the types and levels of activity we plan to deliver.

Looking forward, from April 2023 we will externally assure all load-related investment decisions worth £2m or more. We will also publish options assessments and decision rationale for all 33kV and 132kV interventions, so that stakeholders understand how we have reached our decisions.

6 NDP Part 1 – reporting Network Developments

The preceding sections detail how we have applied our forecasts, through network assessments, options assessments, and detailed design to establish our load driven interventions that we plan to undertake to add network capacity.

Whilst these are a key input to NDP Parts 1 and 2 and form the majority of the additional capacity we will deliver, the NDP requires that we include all interventions that increase capacity. This means we have also included in our NDP Part 1 losses-driven, and asset management-driven interventions which increase network capacity even though this isn't the primary reason for the intervention. Our NDP Part 1 provides a detailed breakdown of our 10-year intervention plans, arranged by GSP and disaggregated by intervention driver. The intervention activities included are detailed in the Table 3.

Activity	Inclusion within NDP
Load related network interventions	**Included – to achieve our Baseline forecast** The NDP Parts 1 & 2 include all planned load driven interventions to facilitate our Baseline plan for the next 10 years. This includes flexibility services, smart and innovation solutions, and reinforcement schemes. These may be driven by thermal, voltage or fault level constraints. These constraints can occur together or independently. In all cases, these network constraints are a result of there being insufficient network capacity to accommodate customer power flows. Headroom at a primary may also be limited by a constraint on the upstream (higher voltage) network. Where this is the case, our NDP Part 1 tables indicate the presence of upstream constraints. We have not included the load-driven interventions needed to enable a higher than baseline scenario (a summary of load-driven interventions for the high scenario is on page 41 of our RIIO-ED2 Business Plan).
Asset modernisation	**Included – where these affect network capacity** The NDP Parts 1 & 2 includes planned asset modernisation activities where these affect network capacity. For example, we list where a condition driven asset replacement increases the rating of the transformer or switchgear being replaced. We have not listed asset modernisation interventions which do not affect capacity. Therefore the schemes listed in the first five years of the NDP may differ slightly from those listed in the LTDS. This is typically true of OHL modernisation/refurbishment activities.
Losses driven modernisation	**Included – where these affect network capacity** The NDP Parts 1 & 2 include planned losses driven modernisation activities where these affect network capacity. For example, where we replace primary or grid transformers, because of the high losses they incur, with new EcoDesign Tier 2 transformers which are of a larger capacity.

Table 3: Types of intervention which add capacity and are included in NDP

7 NDP Part 2 – reporting Capacity Headroom

Part 2 of our NDP forecasts post-intervention headroom across all network groups out to 2050. We've calculated this post-intervention headroom by combining our existing network model, our scenario forecasts, and our known intervention plans.

Our NDP Capacity Headroom spreadsheet data files provide this information for each primary (and grid in SPM) substation/substation group for each year for ten years and every 5 years through to 2050 thereafter. Given the forecast uncertainty in future pathways to achieve Net Zero, we have done this for each of the low, baseline, and high scenarios (see Section 2.2). We provide our headroom calculation for demand and generation separately as the constraints limiting each can be different.

The following sub-sections detail how we have calculated the demand headroom and generation headroom.

7.1 Demand headroom

Demand headroom is calculated as the firm capacity of the substation, plus any capacity added due to planned interventions or flexibility services, minus the forecast level of demand. A positive number indicates spare capacity and a negative number indicates a forecast constraint. Some points:

- The firm capacity is the maximum load the substation (or substation group) can support whilst keeping the network operating safely within limits. For primary substations this is generally the capacity available during single circuit outage conditions.
- When calculating the firm capacity, we consider the season of most onerous demand (typically winter). This is because the ratings of some equipment differ seasonally.
- For multi-transformer substations, the firm capacity considers only the capacity that can be available through automatic processes (e.g. parallel operation of the transformers or automatic changeover schemes).
- For single-transformer substations, the firm capacity values include the capacity that will be available through both automatic and manual switching processes, provided these can be carried out within the time constraints specified in Engineering Recommendation P2.
- The firm capacity of solidly interconnected network groups in SP Manweb must be calculated from network analysis due to the more complex interconnected nature of the system.

7.2 Generation headroom

To calculate the generation headroom, we compared the forecast level of generation against the generation hosting capacity of the substation. The generation hosting capacity considers the reverse power flow capability[17] of the substation/group, and the fault level capability of the equipment[18].

We assess fault level capability through short circuit studies:

- The fault levels are calculated under the most onerous network conditions to yield the maximum anticipated fault currents. The most onerous network condition is considered to be when the following conditions occur concurrently:
    - all generating apparatus is in service;
    - all transformers are set to nominal tap position;
    - the system is intact (N); and
    - fault level contributions are included from all independent generators.

[17] Reverse power flows occurs when generation exceeds local demand. Reverse power flow can cause problems for older transformers, which were not designed to accommodate as much power flow in this direction (tap changers are usually the limitation). Increasing generation in recent years has created widespread areas which experience reverse power flow.

[18] When there is a network fault, the local network experiences a 'fault current'; these are orders of magnitude higher than normal network current. Generators are a source of fault current, so the increasing levels of DG needed for Net Zero will increase prospective network fault current. Switchgear are the assets which are designed to safely isolate network faults, and so are sized to cope with a certain level of fault current. We need to check that generation growth wouldn't increase the network fault current above the rating of the switchgear.

- Fault contributions from synchronous generators and converter connected generators are treated differently. Typical fault current contributions from synchronous generators and converter connected generators are used to determine the available fault level headroom when considering forecast generation.

7.3 Capacity Headroom results

The full suite of capacity headroom results for SP Distribution primary substations (33/11 kV), and SP Manweb grid substation groups (132/33kV) and primary substations/substation groups (33/11 kV), are provided as part of our NDP.

In reviewing the capacity headroom results, it is worth noting:

- Headroom results do not take account of the additional capacity provided through the rollout of Constraint Management Zones (CMZs) or other flexible connection arrangements such as local constraint schemes.
- Generation headroom at a substation/group may be limited by upstream constraints beyond our network boundary. These upstream constraints are flagged in column E within the Part 2 spreadsheets, but are not reflected within the capacity headroom values. Any new generation connections where there are upstream constraints beyond our network boundary will be subject to detailed network assessments to determine the actual generation capacity headroom.
- The SP Manweb distribution network is configured as a mesh network with interconnection at all voltage levels.[19] Headroom results provide the calculated headroom of the substation/substation group. The actual headroom at a particular location within interconnected networks is subject to further assessments, as the changing distribution of demand and generation across the mesh may alter available headroom.
- Demand and generation forecasts are subject to factors which can change over time and influence pre-determined plans.
- The timing and type of network interventions may vary, depending on the rate of change in stakeholder requirements influenced by regional and national policies, and requirements for emerging new connections.
- We have taken all reasonable endeavors to ensure the accuracy of the results using information available at the time of publishing. We are not responsible for any loss that may be attributed to the use of the information presented in this report and the capacity headroom results.

[19] A meshed (a.k.a. interconnected) network means power can flow through multiple routes to the point of use. By comparison, most distribution networks in Great Britain have a radial design, where power typically has only one possible path. Meshed networks give exceptionally high reliability but, once capacity is saturated, are typically more expensive to reinforce.

8 Glossary

Constraint Management Zone (CMZ) – CMZs are areas of network we have an automated control system to coordinate and dispatch different operational solutions.

Customer – means anyone connected to our network and who depends on us for an electricity supply. This includes demand, generation, and storage sites, and IDNO networks.

Decarbonisation – the process to reduce the amount of carbon dioxide (CO2) and other greenhouse gas emissions by introducing new low carbon alternatives and technologies. Much of the UK's decarbonisation strategy is based on switching carbon energy vectors (e.g. petrol/diesel for transport, and natural gas and oil for heating) to electricity and powering them with renewable generation.

Decentralisation – this reflects the extent to which generation is sited closer to demand consumption (or is even undertaken by consumers themselves) via the use of smaller-scale technologies such as solar PV and local energy storage. A less decentralised system would be characterised by fewer, larger-scale generators sited further from where the electricity is ultimately consumed (demand); a more decentralised system would be characterised by more smaller-scale generators sited closer to demand.

Distribution Future Energy Scenarios (DFES) – detailed forecasts we publish annually for our two distribution networks. We work with an external party to determine and produce them. They cover a range of demand and generation metrics (e.g. EVs, heat pumps, different generation technologies) out to 2050. https://www.spenergynetworks.co.uk/pages/distribution_future_energy_scenarios.aspx

Distributed Generation (DG) – generation connected to the distribution network, as opposed to the transmission network.

Distribution network – in England and Wales this consists of overhead lines, underground cables and other network infrastructure that operate at 132kV and below; in Scotland this is the infrastructure that operates at 33kV and below. Nearly all demand in GB is connected to the distribution network; only very large demand users (e.g. the rail network) are connected to the transmission network. Nearly all medium-scale and smaller scale generation in GB is connected to the distribution network; typically only large fossil fuel power stations, offshore generation, and large onshore generation are connected to the transmission network.

Electricity System Operator (ESO) – the company responsible for operating the GB transmission network. They have two main operational functions: balancing the total demand and generation on the system to maintain system frequency at 50Hz, and ensuring transmission power flows remain within transmission network capability and statutory limits.

Extra high voltage (EHV) – all distribution voltages greater than 22kV.

Flexibility – the ability of a consumer or generator to change their operation (i.e. their generation/consumption levels) in response to an external signal. With the push towards the electrification of heat and transport, being able to flexibly utilise demand and generation will help minimise the amount of additional network capacity required, balance the system, and provide system stability – these can all help reduce customer electricity bills.

Grid Supply Point (GSP) – the interface substations between the transmission and distribution network.

GW – equal to 1,000 MW.

High voltage (HV) – all voltages above 1kV up to and including 22kV.

Low carbon technologies (LCTs) – means the range of customer technologies that are needed to deliver decarbonisation. For example, EVs, heat pumps, storage, and renewable generation.

Low voltage (LV) – all voltages up to and including 1kV.

MVAr – mega volt amps (reactive) is a unit of reactive power. It can be useful to help manage network voltage levels. It can describe both the amount of reactive power that a user is importing (e.g. this generator is importing 1MVAr of reactive power"), and the amount of reactive power that a user is exporting (e.g. "this generator is exporting 1MVAr of reactive power").

MW – megawatt is a unit of power (not energy). It can describe both the amount of power that a demand user is consuming (e.g. "this town's peak demand has increased by 3MW due to an increase in EVs and heat pumps"), and the amount of power that a generator is producing (e.g. "3MW of solar PV generation has been installed in this area").

Minimum demand – the point in the year, typically during the summer months, when our distribution network as a whole sees the lowest demand. It is an important study condition (along with peak demand) as a network with low demand can experience voltage control issues.

Net Zero – means the legislated target of reducing greenhouse gas emissions to net zero. For the UK, there are three Net Zero targets:

i. The UK Government has introduced the Climate Change Act 2008 (2050 Target Amendment) Order 2019. This legislation introduces a legally binding target for the UK to have net zero greenhouse gas emissions by 2050. The legislation is available at: http://www.legislation.gov.uk/ukpga/2008/27/contents

ii. The Scottish Government has introduced the Scottish Climate Change (Emissions Reduction Targets) Act 2019. This legislation introduces a legally binding target for Scotland to have net zero greenhouse gas emissions by 2045. The legislation is available at: http://www.legislation.gov.uk/asp/2019/15/contents/enacted

iii. The Welsh Government has introduced The Environment (Wales) Act 2016 (Amendment of 2050 Emissions Target) Regulations 2021. This introduces a legally binding target for Wales to have net zero greenhouse gas emissions by 2050. The legislation is available at: https://www.legislation.gov.uk/anaw/2016/3/contents

Open Networks – this is a pan-industry project involving transmission and distribution network companies, the ESO, the Department for Business, Energy, and Industrial Strategy (BEIS), Ofgem, and other stakeholders. It has done much work developing DSO models, the customer experience, whole electricity system planning and distribution to transmission data exchange, and flexibility services.

Peak demand – the point in the year, typically during the winter months, when our distribution network as a whole sees the highest demand. It is an important study condition (along with minimum demand) as it places the greatest need on network capacity – our network must be able to accommodate peak demand.

Primary substation – see 'Substation'.

RIIO-ED2 – means the distribution network price control period which runs from 1st April 2023 to 31st March 2028. Before this period starts, we will agree with Ofgem the outputs we will deliver during this period, and the funding, incentives, and penalties for delivering those outputs.

Services (aka DER services or flexibility services) – DER can change its import/export position in a controlled manner in response to a signal. This capability can be utilised for the benefit of the network or wider system (e.g. a DER reducing their import to reduce the overall level of demand the network must supply). Where we utilise this capability, the DER is providing us with a 'service'. See also 'Flexibility' and 'Distribution energy resources'.

SP Transmission (SPT) – the Transmission Network Owner for Central and Southern Scotland, that owns the transmission network at 132kV, 275kV and 400kV.

SP Distribution (SPD) – the Distribution network Operator for Central and Southern Scotland, that owns the distribution network at 33kV, 11kV and LV up to customers' meters.

SP Manweb (SPM) – the Distribution Network Operator for Merseyside, Cheshire, North Shropshire, and North Wales, that owns the distribution network at 132kV, 33kV, 11kV and LV up to customers' meters.

Substation – a building or outdoor compound which contains one or more transformers and switchgear protection. The primary purpose of a substation is to change the network power flow from one voltage level to another. In a primary substation the highest voltage is EHV (primary substations are typically 33kV/11kV); in a secondary substation the highest voltage is HV (secondary substations are typically 11kV/LV).

Transmission Network – the high voltage electricity network used for the bulk transfer of electrical energy across large distances. The transmission network takes electricity from large generators (e.g. coal, gas, nuclear and offshore wind) to supply large industrial customers and the distribution network.

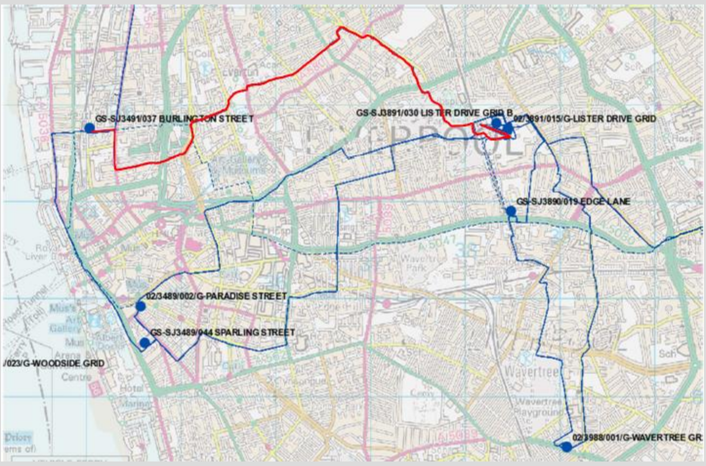
9 Appendix A – Example flexibility use cases

This appendix provides three example use cases where we have included flexibility within our plans to manage network constraints at 33kV and 132kV voltage levels. Where flexibility services are not yet available and we have had to assume the use of network reinforcement, we will retender for flexibility before the reinforcement starts to ensure we are using the most efficient intervention. We have not included use cases of flexibility on the HV and LV network as these are beyond the scope of the NDP.

Use Case 1: Using flexibility to defer major reinforcements

We will use flexibility to defer major reinforcements. For example, in the Carrington–Fiddlers Ferry group we will defer £10.5m of 132kV circuit upgrades, and at Redhouse we are able to defer replacing a 132/33kV transmission transformer, saving our customers £2.8m in exit charges. At Lister Drive in Liverpool, we will combine flexibility with network monitoring and automation to defer replacing 10km of the 132kV cable that runs into the centre of Liverpool (Lister Drive); as well as deferring £9m, this avoids significant disruption for residents.

Case study: Lister Drive 132kV, Liverpool



Background The Lister Drive 132kV network group provides supplies to 163,700 customers including Liverpool city centre as well as the shipping docks and industries along the Mersey River.

Conventional solution is to reinforce by overlaying with a new 10km 132kV circuit in central Liverpool.

Proposed solution is to manage the constraint through RIIO-ED2 by contracting with 8MW of flexibility capacity in combination with thermal monitoring and network automation.

The automation secures the network and maintains assets within safe limits if there are shortfalls in flexibility. The flexibility reduces the hours at risk that could trigger the automated load transfer.

Use Case 2: Using flexibility to manage uncertainty

We intend to use flexibility to manage 38 demand groups in RIIO-ED2 where the forecast loading is approaching limits and flexibility can reduce the risk of network constraints – particularly under higher uptake scenarios. These are the network areas where demand forecasts are high with marginal exceedances over the network firm capacity. The network constraints in these areas depend on the forecast demand/generation being fully realised. Capacity exceedances are minimal and predicted to occur for a few hours in a year. Flexibility services can manage these high loadings through the RIIO-ED2 period, deferring potential investments associated with high uptake scenarios from RIIO-ED2 into RIIO-ED3.

Use Case 3: Using flexibility to reduce the number of hours the network is at risk of constraint

We will use flexibility to help manage the network at sites with high utilisation, where this is in customers' best interests.

For example, flexibility solutions may be able to manage constraints for a few years, but within the RIIO-ED2 period the increasing hours the network is at risk of constraint, and growing magnitude of the constraint, are such that an alternative intervention is required. In these scenarios we have carefully considered the timing of the intervention and the bids received to-date to optimally intervene.

Similarly, where flexibility has been sought but the bids received are not able to fully manage the constraint, we have considered whether the level received may help reduce the hours the network is at risk of constraint. This can help us manage the network while we deliver reinforcements.

We will continue to tender in these locations as we prepare to intervene during RIIO-ED2.

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