Network Development Plan Methodology Document

Strategic Planning

April 2022

Contents

1 Purpose of the NDP Methodology Document

This NDP Methodology document serves to provide transparency and guidance on how the network forecasting and development process for the provision of network capacity is undertaken within Electricity North West and therefore how the NDP is compiled. For detailed insight into how the calculation in the Network Headroom Report are derived, please see the accompanying guidance notes specific to that. The NDP Methodology covers the end-to-end network planning process with sufficient detail to allow stakeholders to understand the approach taken and any associated sensitivities and considerations of the process.

2 Overview of Network Planning Process

Electricity North West's approach for capacity related network planning follows a systematic end to end development process, as shown in Fig. 1 and this document describes the methodology applied at each step.

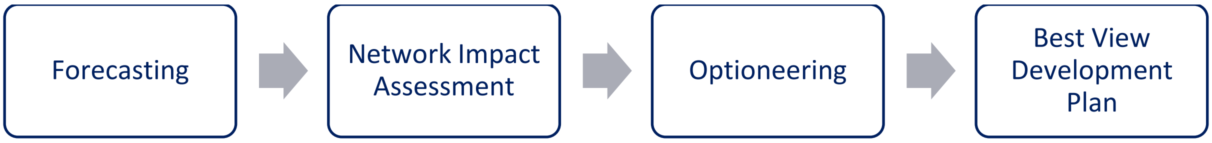

Figure 1 High level capacity related network planning methodology

Forecasts of credible futures are an essential starting point as customers' requirements are expected to continue to change within an evolving energy system influenced by net zero targets. These alternative views of the future allow us to prepare for a range of eventualities including different levels of low carbon technology uptake. Analysis of demand and generation forecasts informs our understanding of where our network will have sufficient capacity and how this varies for each scenario.

Where we identify potential network constraints, we consider mitigation options based on their location, magnitude and nature and timing dependencies. This optioneering process provides a view on future development requirements and is supported in the near-term by a comprehensive cost benefit analysis to support our decision making. All decisions are reviewed and may be revised throughout the progression of each development project.

All steps form part of the ongoing processes using standard network data to reach consistent views of our network capacity as reflected in our standard reports which are published to support our stakeholders as shown in Fig. 2. Relevant network planning data is made available to external stakeholders in a digitised and open form to permit their further analysis to extrapolate network capacity reporting including that in our Distribution Future Electricity Scenarios (DFES)[1], and heat map. The manner in which the data from this modelling was made available to other stakeholders, in line with Data Best Practice guidance.

This document comprises of four main sections which follow the four high level steps of our investment planning:

- Section 3 outlines the basis and development of the regional scenarios that have informed our best view investment plan for the next 10 years;

[1] Electricity North West, Distribution Future Electricity Scenarios (DFES). Online: www.enwl.co.uk/dfes

- Section 4 explains the next step and how we assess the impact on our network of forecast electrical requirements;
- Section 5 presents the solutions we apply including use of flexibility and discusses our decision-making processes.
- Section 6 discusses how we have prepared our Best View Investment Plan.

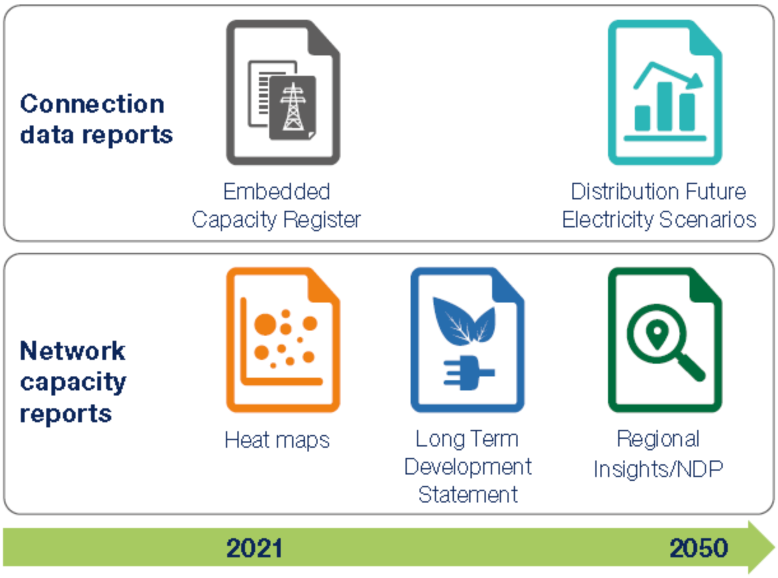

Figure 2 ENWL network and capacity reports

3 Forecasting

3.1 Overview

A wide range of long-term forecasting scenarios for electricity demand and distributed generation are used in network planning. The forecasting components that are described in this section are shown in Figure 3 and are based on the high-level components listed in the NDP FOS Methodology[2] guidance. The NDP FOS methodology guidance is based upon Ofgem's framework for the reporting of the methodology underpinning RIIO-ED2 load related investment programmes of all DNOs. This consistency of approach assures that the network developments sign posted within the NDP are aligned with the approach taken for DNO's RIIO-ED2 load related investment plans. The RIIO-E2 business plan submission used a range of compliant scenarios in development of the load related investment plan. The 2020 Central Outlook Scenario was the basis for Electricity North West's RIIO-ED2 'baseline' investment programme. In 2021 Electricity North West developed an additional scenario that replaces Central Outlook from our previous DFES publications.

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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

This following section on forecasting summarises all scenarios used to support network planning and explains their link with DFES and the standardisation of the ESO FES and DFES. The 5 scenarios detailed in this section, are all used to evaluate future capacity in the Network Headroom Report.

We also explain how the various demand components affect peak demand and how the adopted modelling and stakeholder engagement captures local trends to allow network planning to target investment only where and when needed.

Unlike Central Outlook that adopted central and average assumptions, the Best View is the region's highest certainty scenario and focuses on high certainty in the next 1 to 10 years. All scenarios are modelled using regional data and out unique bottom-up methodology developed as part of our ATLAS project, which makes them representative of the North West.

Our Best View scenario aims to provide clarity and remove the complexity of multiple scenarios for our customers and stakeholders. As the region's highest certainty scenario when compared to three key criteria, Best View can help stakeholders understand local demand and generation trends over the short-term. The Best View scenario can provide the highest certainty basis for assessing network impact and the need for interventions in the next 10 years. Therefore, it has been used as the basis to present asset and flexibility options in our Network Development Plan. Beyond this 10-year time horizon presenting Best View with all other DFES scenarios can importantly provide insight into the range of uncertainty.

When developing the best view investment plan for the next 10 years as presented in the Network Development Report, we have used Best View scenario for the presentation of requirements, but we importantly use the other four scenarios in to enable a sensitivity analysis when considering magnitude and timing of constraints. Any investment decision that is made is based on the observed network conditions and local stakeholder information at the time.

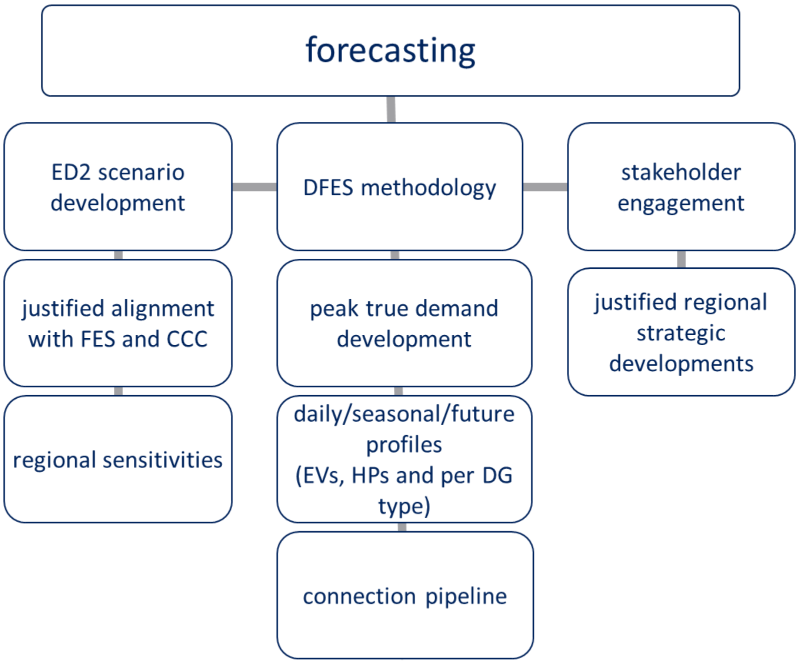

Figure 3 Forecasting Components

3.2 2021 Scenarios

All DNOs undertake an annual forecasting activity which is presented in their respective annual Distribution Future Electricity Scenarios (DFES) publications. DFES provides granular scenario projections for electricity demand, DG and battery storage that incorporate regional factors and can be used at a local level for strategic planning of distribution networks. These projections are informed by local stakeholder engagement to understand the needs, plans and delivery progress of local authorities and other stakeholders. The DFES provides an evidence base for DNOs to develop the business case necessary to support future investment, including regulated business plans.

As part of Electricity North West's 2021 DFES we have produced a set of five scenarios; Steady Progression (SP), System Transformation (ST), Consumer Transformation (CT), Leading the Way (LW) and Best View (BV). Following the whole system FES standardisation process developed in Worksteam1B Product 2 of the ENA Open Networks project, the first four scenarios now have the same scenario framework, names and high-level assumptions with ESO FES and all other DNOs' DFES. As shown in Fig. 4, the common two axes to define scenario assumptions are speed of decarbonisation versus the level of societal change.

The real value of this standardisation is to create a common language and familiarity for stakeholders when accessing electricity demand and generation forecasts from multiple organisations. For example, use of this common language means that high uptake trends of EVs should be expected for LW across the industry. However, this does not mean that these trends follow the same pattern or volume across all regions or between regions within the same license area. Engagement with local stakeholders and the influence of distribution network planning on stakeholder decisions allows us to improve the accuracy of regional forecasts.

A fifth scenario, Best View (BV) was introduced in 2021, focusing on the most likely forecast in the North West region. BV replaces Central Outlook from our previous DFES publications. Unlike Central Outlook that adopted central and average assumptions, the Best View is the region's highest certainty scenario that focuses on high certainty in the next 1 to 10 years. All scenarios are modelled using regional data and our unique bottom-up methodology developed as part of our ATLAS project, which makes them representative of the North West.

Further information on the methodologies we employ in the creation of our DFES and the 2021 DFES forecasts is available on our website.

Even though stakeholder engagement has allowed us to model evidence based local plans in DFES, it has also revealed that local policies are not yet in place to accelerate decarbonisation to meet net zero carbon targets before 2040. Therefore, all five scenarios in our 2021 DFES are driven by national policies and local factors reflected through our cycle of engagement with local stakeholders and ATLAS bottom up forecasting methodologies. Apart from the SP scenario, all our other four scenarios meet the UK government's 2050 net zero carbon target. Specifically, CO, CT and ST scenarios meet net zero by 2050 and our LW scenario meets the target by 2045.

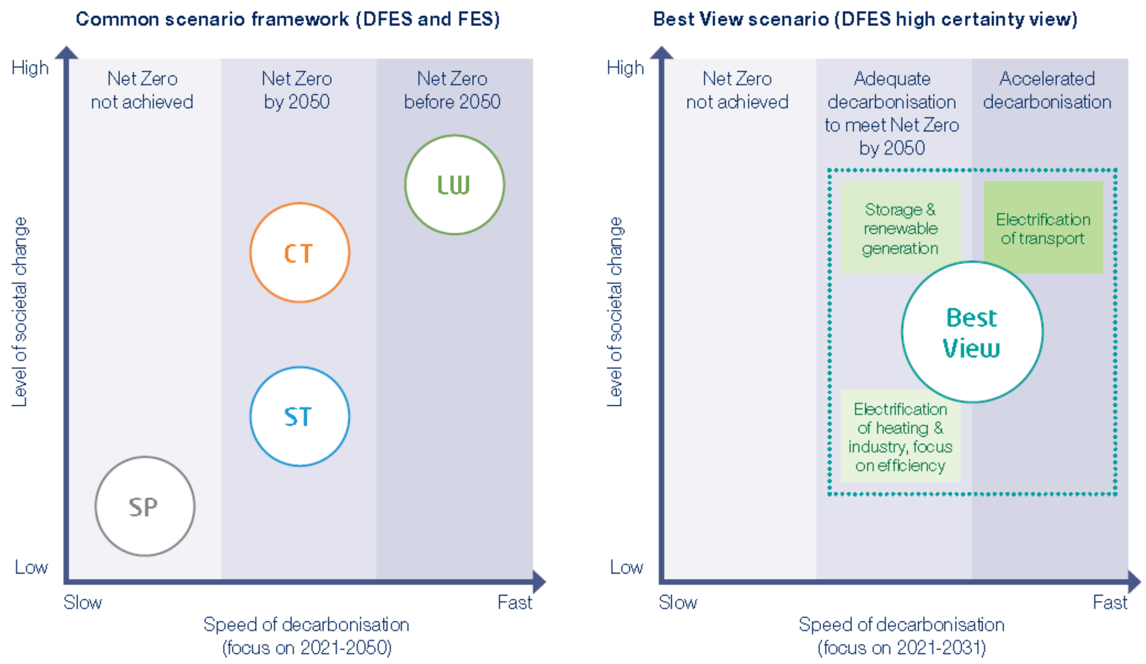

Fig. 4. **Electricity North West DFES 2021 scenarios**

3.2.1 Forecast parameters

We forecast the following parameters for each scenario up to 2050:

- LCT numbers
  - EV volumes
  - Heat pump volumes
  - Generation and storage capacities
- Electricity demand
  - Energy consumption
  - True peak demand

True demand is the demand that needs to be supplied at a local level if local generators are not exporting, e.g. due to maintenance or low wind for wind farms. It is particularly important in distribution networks for numerous reasons:

- Local demand is less diversified than at the national transmission level, eg in FY20 the sum of individual primary substation peaks in our South Manchester group was 1/3 more than the peak demand for the group observed at the transmission interface. Diversity is even lower in the HV and LV parts of our distribution network that are closer to customer points of connection.
- Distribution network security of supply assessments in accordance with EREC P2/7 (license condition) require consideration of local true (gross) demand as a minimum. An allowance for the contribution of local generation to security of supply is modelled following EREC P2/7 considering that local generation is less diversified as we move to lower voltage levels. The allowance is typically significantly less than the sum of the generators' rated capacity values.
- Demand forecasts produced with a transmission or capacity market focus, eg ESO FES, can be inclusive of the diversified effects of small local generators that appear to reduce the consumption on distribution network customers because they are used to determine the level of demand that needs to be supplied via the transmission network, rather than the local distribution network.

3.2.2 Domestic and non-domestic demand effects on peak demand

The current split of peak true demand forms the basis for developing future changes in domestic and non-domestic (I&C) demand to be reflected in our forecasts. Our information on individual customers and which substation they are connected enables us to develop precise understanding of the split between domestic and I&C customer demand.

Fig. 5 shows how the current and future winter peak demand on our network breaks down into different customer and usage types. Even though currently domestic demand accounts for around one third of electricity consumption in terms of energy in MWh, it accounts for approximately half the winter peak demand, mainly due to the use of domestic electric heating coinciding with the time of overall peak demand. Looking forward to 2030 additional peak demand requirements are largely driven by planned developments, EV charging and HP usage. It should be highlighted that our DFES peak demand assessments are based on local half-hourly demands informed by local measurements across substations and generators. Using historical half-hourly domestic and I&C demand values allows us to build local and per asset forecasts more accurately than if we took a national averaging approach.

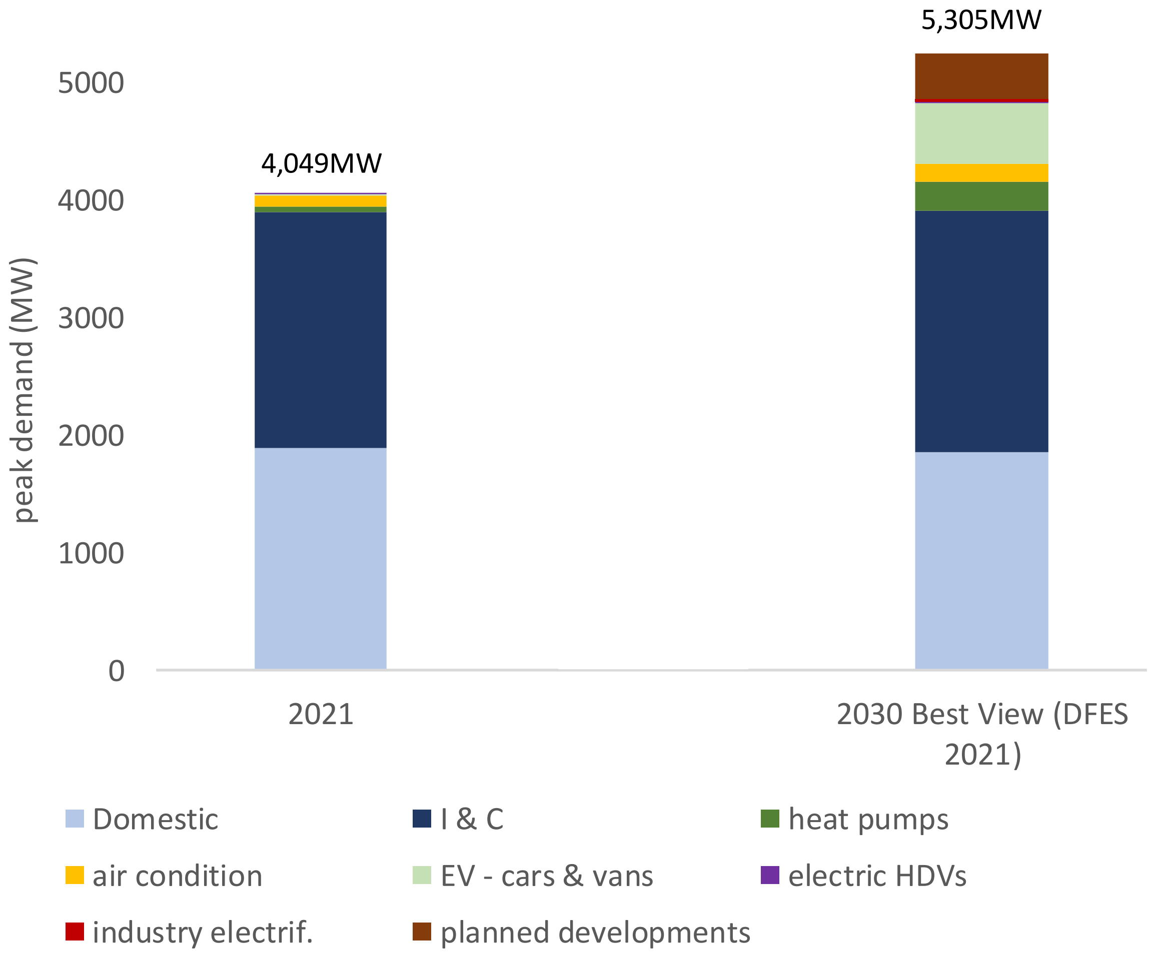

Fig. 5. Decomposition of peak demand

3.2.3 Modelling true peak demand

To understand the effects of LCTs on future local peak true demand, a critical modelling aspect beyond LCT volume uptakes is to consider how changes in future behaviours and technical characteristics will affect the way and times that these LCTs will consume electricity. We do this in practice through the use of diversified LCT profiles which show how EV charging and heat pumps can on average affect demand at different times through day, as well as how these profiles can change from 2020 to 2030.

In addition to modelling local factors, e.g. building stock and planned developments of local stakeholders to capture differences across our region, it is critical to model each demand component using half-hourly measurements and data. This is necessary to quantify how domestic, I&C, EV charging and heat pump demand can affect local peak load or even shift the time of peak demand to a different time within the day or month/season.

3.3 Stakeholder engagement

Our engagement with local stakeholders including local authorities (LAs), customers, energy communities and investors provides valuable inputs to our ATLAS forecasting methodology used to produce the DFES. As shown in Fig. 6, these inputs include both data provided directly by stakeholders but importantly also how implications of our network development affect stakeholder decisions and connection behaviour.

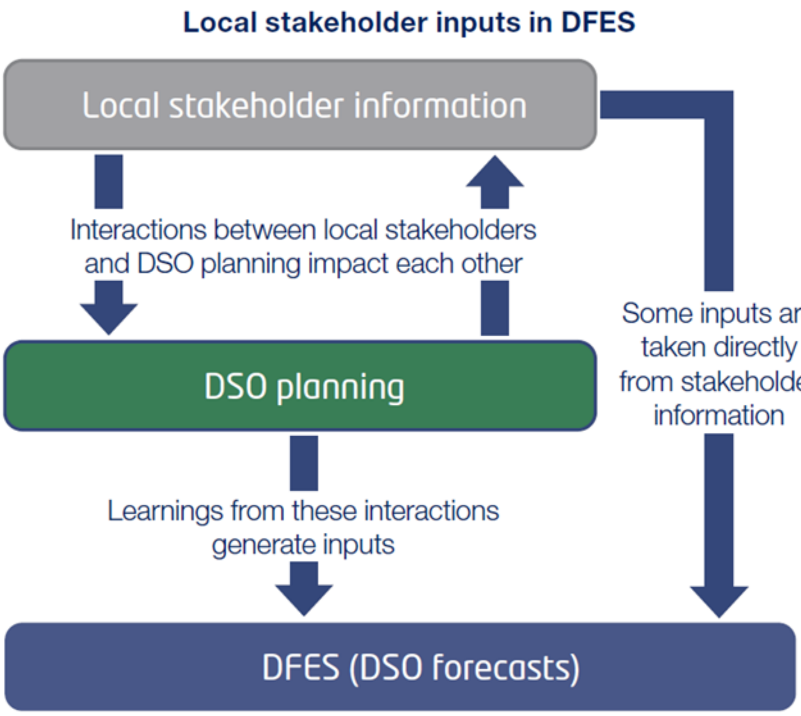

Fig. 6. Local stakeholder inputs in to the ATLAS methodology used to produce DFES forecasts

At a high level, the DFES inputs from local stakeholders can be grouped as:

- LA decarbonisation policies affecting consumer choice at local level;
- planned developments with associated connection quotes (connection pipeline); and,
- established plans of major developments backed by LAs, which are more efficiently accommodated on to our network by holistic and strategic investment.

3.3.1 Incorporation of connection pipeline

Our demand growth and per DG type DG forecasts include our connection offer and acceptance pipelines for demand and DG projects using confidence factors in accordance with our ATLAS methodology. This process can be summarised as follows for demand projects:

- **for HV and LV demand connections:** historical performance is identified using data from a sample of several thousand quotes, acceptances and energisations of commercial and industrial projects. This data is first used to establish the percentage of quoted connections that are accepted and the percentage of these that go on to energise their connection. We assume that these historic rates are applicable to the future and can be used to scale known volumes of offers to be included in our demand forecasts. These percentages can be considered as a first set of confidence factors which are identified separately for the north and south of our license area. A second set of confidence factors is identified from the analysis of the maximum demand (MD) reached by energised projects, compared to their contracted maximum import capacity (MIC). As might have been expected, the confidence factors for connection offers is less than those for connection acceptances. The two sets of confidence factors are then applied to present offered and accepted demand connection pipelines.
- for EHV demand connections: likelihood indices are used based on information provided by customers as well as by our Connections business teams. We examine progression to check where each project is within their development and connections process and importantly consider the expected timeline of energisation and demand growth, as well as the customer type to assign realistic demand profiles (eg, a Network Rail connection will be modelled using average half-hourly demand profiles from existing railway sites).
- for DG and grid scale battery storage connections (EHV and HV): we consider only accepted connections, given that historical analysis has revealed that a large number of connection offers do not progress.

3.3.2 Regional strategic developments

Stakeholder engagement provides valuable input to our DFES and can have a significant influence when we learn of established plans which may require us to strategically invest in network capacity. Regional strategic developments are included in the DFES because such large focussed development hot spots could be at a planning stage but have not applied to us for electrical connections or have a connection offer yet.

Involvement of multiple potential customers in a small area over a short development window means that it is important that we take a holistic view rather than making less efficient piecemeal network interventions. Regional stakeholder developments are only included in our DFES forecasts when we are confident that they are likely to go ahead and we have robust evidence to support this confidence. As part of our certainty ranking shown in **Error! Reference source not found.** we evaluate various types of justification, i.e. Local Authority plans, national/local funding (getting building etc), developer enquiries. The level of justification may vary if we identify other needs in an area, for example asset health or increased connection activity in a neighbouring area.

Fig. 7 shows the Mayfield example of a regional strategic development in our area. Using the certainty ranking this development area has been selected to be modelled in DFES as we have identified secured funding with strong LA and national backing. More specifically, apart from the significant activity shown in the connections pipeline for this area, there are also:

- Local Authority driven developments as part of Greater Manchester Spatial Framework (GMSF) agreement for regeneration of Manchester (GM Strat 7 – North East Growth Corridor);
- HS2 Government backed national infrastructure scheme to develop high speed interconnection between the North and London; and,

- planned University of Manchester re-development programme for the north campuses (former UMIST).

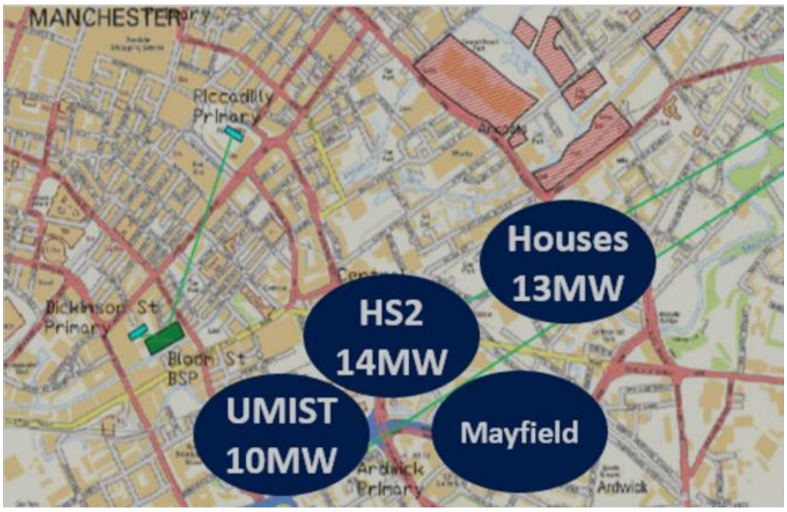

Fig. 7. The Mayfield example of regional strategic development

The per year demand growth and the planning timeline of several robustly justified local stakeholder plans have been modelled in DFES and the forecasted demand has been modelled in network studies to assess network impacts.

4 Network Impact Assessments

4.1 Overview of network impact assessments

Our forecasts of electricity demand and distributed generation are used as inputs in network impact assessments. These assessments allow us to understand if future requirements for power at different parts of the network can be supplied by the existing network capacity or if interventions are required to accommodate the demand and generation growth. Fig. 8 shows the components of our network impact assessments that are described in this section and are based on NDP FOS guidance and Ofgem's framework for the reporting of the methodology underpinning RIIO-ED2 load related investment programmes.

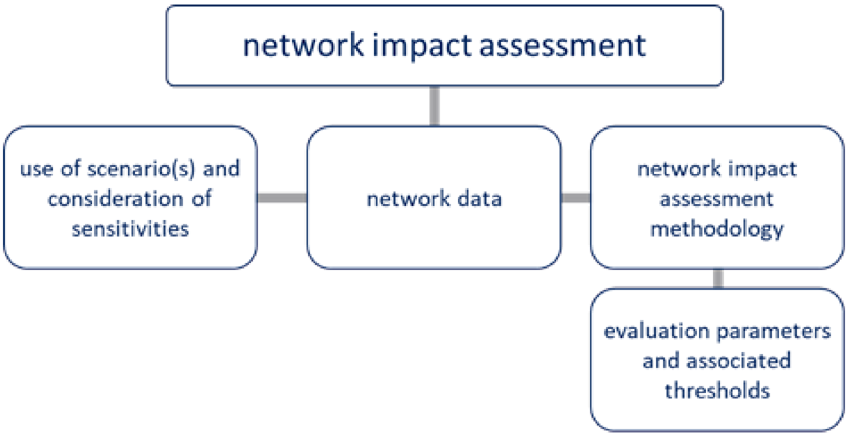

Fig. 8. The components for network impact assessment from Ofgem's reporting framework for the RIIO-ED2 methodology of the load related investment programme

4.1.1 Introduction to network impact assessments

Network impact assessments are carried out for both the EHV and secondary (HV & LV) networks to determine future network development plans and investment requirements. Different approaches are applied at different voltage levels due to the differing size, demand diversity, volume drivers and complexity per voltage level.

Our approach to assess EHV network impacts, are detailed in this section of the methodology document and reflect the approach taken for the Network Development Report. For a given scenario network impacts are based on forecasts per substation and detailed power system modelling (i.e. using IPSA power system analysis software). This analysis allows us to locate where network parameters exceed limits including quantify thermal, voltage and fault level, whilst also allowing us to analyse and compare the effectiveness of alternative solutions.

Our approach to assess HV and LV network impacts for a given scenario is based on the use of our bespoke Future Capacity Headroom (FCH) tool to quantify thermal, voltage, fault level and harmonic distortion issues.

4.1.2 Network data for impact assessments

A number of key data sources are used in the network analysis that underpins our investment planning. Our Master Asset Management System (MAMS) database contains a corporate auditable record of our transformer and switchgear ratings, of which our system study models are built upon. Cable records are contained in our GIS system and again the master modelled data is verified against this source and based on these corporate records. Future demand and generation data is from our detailed DFES scenario forecasts which have been produced for our license area. Our Long-Term Development Statement and published DFES report are also key sources of information for our detailed study work.

For the modelling of our EHV network in impact assessments, the detailed electrical parameters of all EHV assets, ie impedance and susceptance values for transformers, lines and cables, as well as operational aspects, e.g. on-load tap changer settings and voltage targets, are modelled in IPSA power systems analysis tool. Our IPSA network model exceeds 3,000 nodes and covers the whole 132kV and 33kV network and incorporates an equivalent reduced network representation of the transmission network, including detailed information on transformers and circuit ratings.

HV and LV network impact assessments are undertaken using our tailored FCH tool which models the actual connectivity of the whole HV and LV network (over 300,000 nodes including over 35,000 secondary substations) and allocates half-hourly loading to the whole of the network from the combination of regional forecasts (per LA) with measurements from all HV feeders (over 3,000 feeders) in our license area.

4.1.3 Forecasts in network impact assessments

Our EHV network impact assessments of future loading on our network are undertaken using local peak demand forecasts, as well as those for storage capacity and DG per generation type for each EHV substation (around 450 substations). The analysis is carried out for each of our DFES scenarios. How forecasts are applied in network assessments is described in the following sections. Individual substation peak demand forecasts are applied either in isolation from adjacent substations to identify local constraints; or, together with adjacent BSPs and primary substation demand growth, especially for extraordinary regional EHV developments.

For the HV and LV network impact assessments, forecasts per LA are used as inputs to our FCH tool to identify locations and volumes of thermal and voltages issues in each region. These forecasts comprise volumes of LCTs (EV, heat pumps and rooftop PV), as well as domestic and non-domestic demand trends per LA. Future peak demand across the whole HV and LV network is estimated by adding half-hourly measurements at the head of HV feeders that are typically the last point of monitoring to aggregated LCT consumption profiles determined by combining LCT volume forecasts multiplied by LCT half-hourly profiles (ie, diversified for HV and non-diversified for LV).

For the assessments of harmonic distortion issues, LCT forecasts of the number of EVs per secondary substation (ie, around 35,000 substations) are used as inputs to an empirical rule based on a detailed WPD trial study.

4.1.4 Use of Scenarios in Network Planning

Our Best View scenario aims to provide clarity and remove the complexity of multiple scenarios for our customers and stakeholders. As the region's highest certainty scenario when compared to three key criteria, Best View can help stakeholders understand local demand and generation trends over the short-term. The Best View scenario can provide the highest certainty basis for assessing network impact and the need for interventions in the next 10 years. Therefore, it has been used as the basis to present future asset and flexibility requirements in our Network Development Plan. Beyond this 10-year time horizon presenting Best View with all other DFES scenarios can importantly provide insight into the range of uncertainty.

When developing the best view investment plan for the next 10 years as presented in the Network Development Report, we have used Best View scenario for the presentation of requirements, but we importantly use the other four scenarios to enable a sensitivity analysis when considering magnitude and timing of constraints. The four other scenarios are useful to help define this range of uncertainty even in the near term and are used to ensure that options for responding to an uncertain future are not foreclosed. Any investment decision that is made is based on the observed network conditions and local stakeholder information at the time.

4.2 EHV network impact assessments

4.2.1 Thermal and voltage issues

Thermal assessments of our EHV network loading are undertaken in two stages; an initial approximate assessment is followed by more detailed studies where required. The forecasted peak demand for each year up to 2030/2031, ie covering the 10-year period of the Network Development Report, is compared to the existing firm capacity of each EHV substation, ie all BSPs and primary substations. This comparison is carried out for the Best View Scenario as it is our most certain scenario for the next 10 years. Should the anticipated demand growth approach a substation's firm capacity, then detailed studies are undertaken to explore the issue further. We use the our IPSA models to study our 132 to 33kV network down to primary substation HV busbar level.

Load growth figures in MW and MVAr (based on forecasted MVA and assessed power factors at times of peak load) are entered into the model to enable detailed load flow simulations for different years and scenarios. The transmission system is assumed to remain constant. Studies using these models are undertaken to identify network overloads and non-compliant voltages. Solutions to these network overloads are then determined through detailed analysis, with a range of alternative reinforcement options being explored.

Our Network Development Plan is based on interventions being required when thermal capacity exceeds 99% of existing firm capacity ratings for 9 hours per annum. This level has been selected for its alignment with Ofgem Load Index 5 definition and signposts interventions over the 10 year NDP period to ensure there is sufficient time to initiate planning and development of whole system solutions.

4.2.2 Short circuit studies

The uptake of DG and battery storage is predicted to see significant growth across all our scenarios up to 2051. The proposed uptake of generation will increase the fault level across our network. Different technologies contribute varying levels of fault current on to our network, with inverter-based technologies such as PV and batteries contributing less than synchronous based technologies. Fault level is a key metric to manage on our network to ensure we can continue to operate the ENW network safely, protecting our operational colleagues from danger and ensuring plant is not exposed to potential disruptive failure.

EHV and primary substation HV fault levels are simulated using our network models. We maintain a Master IPSA model which represents the network as it is today, inclusive of latest energised DER connections. The model also incorporates a reduced representation of the transmission network set up for the maximum fault level operating condition.

The Master IPSA model is updated with the relevant year forecasts of peak demand and the corresponding increased G74 motor fault in-feed contributions that are required for fault level calculations. In addition to this, forecast generation is also included, with an estimation of additional synchronous and non-synchronous inverter-based fault level contributions factored into the model at primary level. The study steps we have undertaken are as follows:

- for primary and BSP substations (fault levels at 33, 11 and 6.6kV busbars):
    - calculations were undertaken using the latest Master IPSA model at the time;
    - the G74 contribution at each primary in the Master model was then modified based on the Best View forecast for the relevant year;
    - forecast DG per primary is broken down by technology type which allowed overall figures for inverter connected and non-inverter connected generation to be derived for each primary;
    - for inverter connected generation a fault contribution of 1 x full nominal current was assumed. For 'make' fault level a factor of 2√2 was also applied;
    - for non-inverter connected generation a fault contribution of 4 x nominal current was assumed. For 'make' fault level a factor of 2√2 was also applied;
    - fault levels are calculated using the Master ISPA model with the increased G74 contribution, and then the 11 and 6.6kV fault levels for each primary were increased individually to include the contribution of non-inverter and inverter connected generators as per the above;
    - the calculated HV fault levels were compared to the existing switchgear 'make' and 'break' ratings, with the sites where the estimated future fault make level exceeded 99% of the corresponding make rating was identified for intervention.

The main impact on 33kV fault levels comes from the large accepted generation schemes, which are included in the model and impacts due to forecast 33kV generators are greatly dependent upon where in the network they connect. Investment to address fault level issues associated with new connections are accounted for in connections driven reinforcement budgets.

Our Network Development Plan is based on interventions being required when make fault levels exceed 99% of existing 'make' switchgear 'make' ratings. This level has been selected instead of ENWL 95% policy level because although our simulated short circuit levels are inaccurate, they are considered to be cautious due to our use of pessimistic assumptions for equipment parameters and operating conditions.

4.3 Conversion of System studies results into capacity values

4.3.1 Thermal Headroom Calculation

A key output of the Network Development Plan is a workbook which allows users to quickly view the forecast thermal headroom availability at each Primary and Bulk supply point. This has been designed to allow of the five different scenarios to be viewed at once, so the differing impact of each can be viewed. Specifically, a detailed year on year forecast is covered out to 2031, before the incremental steps increase to 5 years out to 2051. The NDP does not cover the availability of transmission capacity but we do work closely with the transmission owner to ensure our customer connections requirements can be met.

The results are driven through a relatively simple process where the firm and non-firm capacity of each Primary and BSP are compared to the yearly forecast demand in a specific scenario. Firm capacity allows for the connection of demand which is secure for a first circuit outage at a specific site. Demand connected under non-firm arrangements can be disconnected or constrained under a specific outage. Non-firm capacity is based typically on short term ratings of network assets but is based on a system intact network.

Red cells in the workbook denote a short fall in capacity and are used to point us towards areas where an intervention will be required. Details of proposed interventions in the near to short term window are included as part of the overall NDP publication, collated by Grid Supply Point. These results can also be used to allow us to identify areas where a flexible or demand side management contract could be utilised to enable a net zero option to be developed to offset a traditional reinforcement intervention.

4.3.2 Fault Level Headroom Calculation

To determine the forecast headroom based on fault level on our network a process has been developed using our IPSA Network Model and Python scripts. The DG forecast for inverter and non-inverter-based generation including a G74 contribution based on the demand forecast, is used in an IPSA network model simulation which is run for each year and scenario. The FL results generated at each site from this are then converted into a headroom figure for each site and tabulated in to the workbook.

The headroom figure is determined through a VBA script which takes the existing switchgear rating at a given site and subtracts the IPSA model forecast FL at that site from it. This difference can then be used to determine a FL headroom in MVA based on the system voltage and given technology type, assuming typical contribution from Synchronous (4 x FLC) and Non-Synchronous (1 x FLC) generation technologies.

High level overview of the process -

Results produced cover different technology types and are displayed as such in our workbook, with distinctions identified between synchronous and non-synchronous technologies. Like the demand results, negative values and red cells indicate areas where there is a shortfall in fault level headroom and allow ENW to focus network investment in these areas. Options such as operational management of fault level or the traditional replacement of insufficiently rated switchgear, can then be utilised to address the fault level shortfall that has been identified. It is worth noting that the recent DFES forecasts predict a reduction in fault level contribution in the mid to late 2040s. This assumes that some of the synchronous generation reaches end of life and begins to be decommissioned from the network.

5 Network Solutions

5.1 Network development planning

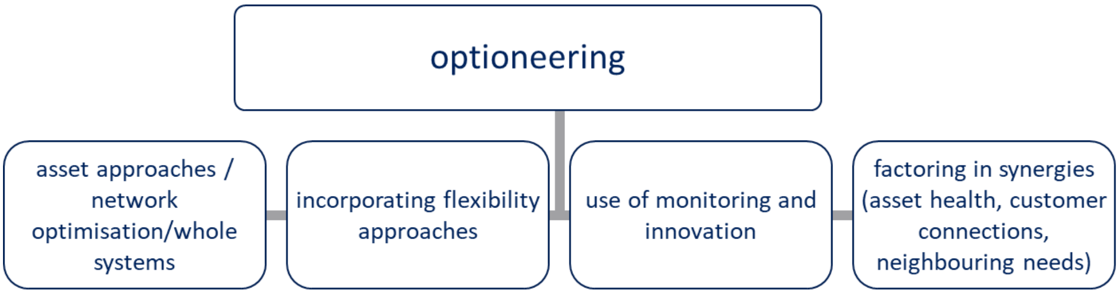

Fig. 9. Components considered in optioneering to ensure optimal network development planning

Comprehensive optioneering including the components shown in Fig. 9 is undertaken following the identification of network issues through our network impact assessments. Alternative approaches are thoroughly assessed to ensure that the optimal development plan is identified, considering the timing of interventions and not foreclosing future pathways. For development of the EHV network, this is supported by use of rigorous cost benefit analysis which ensures that flexible solutions are considered equitably alongside traditional asset solutions.

5.2 EHV network development

5.2.1 EHV load related interventions

High level reinforcement solutions for all identified thermal and fault level issues are developed via desktop exercises for individual named schemes. These solutions consider the overall system performance and the status of neighbouring parts of the network to ensure efficient and economic development of the network. Through our extensive optioneering, we develop a range of solutions to explore the capacity and benefits of alternative approaches. Typical solutions include:

- Reconfiguration of networks to redistribute load;
- Installation of interconnecting circuits to transfer power flows to less loaded parts of the network;
- Use of flexible services and energy efficiency;
- Installation of additional assets, including strategic interventions where we consider holistically an area with multiple forecast constraints to review the efficiency and economics of a single solution;

- Replacement of equipment with greater ratings and overlay of circuits to increase capacity; and
- Other innovative solutions.

Use of power system analysis software IPSA enables us to develop whole systems solutions which can ensure that targeted and focused investment is made, reducing the possibility of investment leading to stranded assets. The range of solutions can be developed further before being subjected to a Cost Benefit Analysis (CBA) to determine the best value for money solution.

5.2.2 EHV fault level interventions

Fault level management is a critical network safety factor examined by our network impact assessments. When exceedances are identified, planned interventions traditionally take the form of making replacements with higher rated equipment but could also be a non-traditional innovation solution which does not require the switchgear to be replaced. This could be network rearrangement to lower fault level or it could be the implementation of an innovation project such as Respond. Selected solutions are based on proven techniques which we consider to be deliverable solutions within required time period of a project based on acceptable equipment outage, consents and acquisition risk.

We will monitor ongoing smart technology developments and where possible incorporate these into our delivery plan.

5.2.3 Use of Innovation and monitoring

Apart from traditional asset solutions to tackle load related issues, innovative and flexible solutions can be the alternatives that allow us to improve cost efficiencies. Using them we can also mitigate any risks associated with excess loads and lead times of asset solutions.

Innovation benefits are derived in different parts of our business and delivered directly to our customers, eg in the form of reduced energy bills if they consume less energy with voltage control. Our CLASS, Quest, Celsius, C2C and Enhanced Voltage Control innovation projects can support solutions for thermal issues, whereas our Respond and Investigation of Switchgear Ratings can do it for fault related issues. It should be noted that some of the innovative approaches are already business as usual and integrated into the costs before any discount is applied.

Even though primary substations are currently the last point of monitoring and this limits our ability to procure flexible services to tackle load related issues at lower voltages, installation of monitoring and the further roll out of smart meters in the final years of the RIIO-ED1 period will increase our visibility in HV and LV networks. This data will provide increased visibility of our HV and LV networks, allowing us to understand utilisation of the network and define our requirements for flexibility services at these lower voltage levels.

With approximately 35,000 secondary substations located across the North West, it is estimated that we will have up to 200 opportunities available each year, facilitating the growth of residential flexibility and energy efficiency markets and fulfilling our role as a neutral market facilitator.

We will continue to act in the best interest of our customers, in developing innovative solutions and to procure flexibility and utilise energy efficiency where it is economic and efficient to do so.

5.2.4 Flexibility Services Approach

Electricity North West has a flexibility first approach to network development when a capacity need is identified. It is our intention to procure flexibility wherever possible to avoid conventional network reinforcement along as it is economic to do so when compared to the traditional asset-based solution.

Our approach to the use of flexible services to support a capacity requirement can be two-fold; flexible services can be a key interim solution while we assess load growth and a wider strategic conventional reinforcement therefore avoiding inefficient piecemeal network expansion and stranded assets. Alternatively, flexible services also allow us to mitigate the risk if demand growth is accelerated and there is a long lead time with a there is a long lead time associated with asset-based interventions. In some instances, depending on the level of flexibility market in the location of the capacity requirement and the scale of the capacity requirement, flexible services could be considered as an enduring network solution.

Our 10-year Best View Development Plan as presented in the Network Development Report shows the future view of requirements and signposts the needs for flexibility services.

We publish flexible service requirements on a bi-annual basis (March and October) for all forecasted EHV capacity requirements two years in advance. This approach allows us to test the market response as close in time as possible to the capacity requirement materialising. In most cases this still allows sufficient time to implement an asset solution if required, once the results of the flexibility tender are evaluated. Those identified requirements in the Best View Development Plan are reviewed on annual basis in alignment with the latest DFES. Where further data is needed to capture on going demand growth or validation monitoring may be deployed

Half-hourly through year capacity balancing requirements across our EHV network can be identified using the detailed assessments supported by our ATLAS forecasting methodology. This allows us to define detailed flexibility requirements, such as number of days per month, energy requirements per day and capacity requirements per season to procure the required capacity of flexible services only when they are needed.

The identified flexible service requirements are then issued to the market via numerous channels. At this point we undertake extensive engagement to promote these requirements and facilitate participation within the market. Following closure of each flexibility tender, bids are assessed to determine their technical and economical compliance and a cost benefit analysis undertaken comparing the proposed flexibility to all alternative solutions.

5.2.5 Considering synergies

Further work is also carried out to cross reference load related programs of work with the condition-based asset replacement programme. This ensures that all possible synergies from efficient planning to phasing and timing of interrelated works can be captured. Carrying out planning in this co-ordinated manner can lead to efficient resolution of network issues and can maximise investment benefits.

Bi-annual reviews of connections activity outside of the DFES process are also be undertaken to identify regions with high levels of connections activity which may trigger strategic reinforcement. Flexibility can then be used to mitigate risks associated with the potential that actual demand growth associated with the connections pipeline materialises beyond the expected based on historical performance that informs the confidence factors used in the forecasts.

In the development of efficient network plans, a joined up whole systems approach utilising customer and stakeholder's partnerships will always be explored. Co-ordination and collaboration with regional stakeholders, industry and other energy providers is key developing low costs whole systems outcomes. We will continue to foster our flexibility first approach; this shows our intention to develop flexible options utilising customer capabilities. We utilise data exchange activities and joint liaison meetings with other network operators to identify and analyse where there may be synergies between our capacity requirements and the opportunity to develop cross boundary solutions. We have a strong track record of engagement with the ESO, IDNOs and our DNO neighbours though which we attempt to discover whole system opportunities and shall provide evidence of this in our whole systems activities register.

6 Best View Development Plan

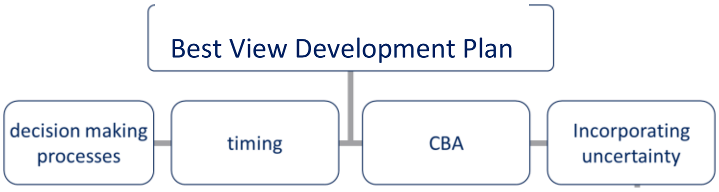

Fig. 10. Components considered in the solutions selection of the load related investment plan.

6.1 Decision Making and Use of CBA

To select the best view solution for a project for incorporation into a strategic investment programme, the full range of solutions for that project as identified in the optioneering process are compared. Apart from an element of optimisation in terms of a quantitative minimisation of costs and risks among solutions, an element of judgement is applied in our decision making to ensure that multiple vectors are taken into consideration to allow us to decide after seeing the "full picture". To do that we need to consider practicalities and other qualitative factors to complement the quantitative analysis.

We follow Ofgem's CBA guidance when undertaking cost benefit analysis to inform our decision-making processes and identify optimal solutions. More specifically:

- for all proposed EHV asset solutions the Common Evaluation Methodology (CEM) tool developed in Open Networks and including Ofgem's RIIO-ED2 CBA has been used to compare them with flexibility and other alternative options;

6.2 Timing and uncertainty

The CBAs consider the "do nothing" and deferral of interventions, eg using flexibility services as an interim measure. This is an important approach it will allow us to use flexible services to address the risk of stranded assets across all voltages and delay greater network investment until demand growth materialises. This will also allow us to mitigate any risks for excess load in the opposite case when demand growth is accelerated and there is a long lead time associated with asset-based interventions. Our RIIO-ED2 LV monitoring programme will facilitate the expansion of flexibility services to the whole of our network.

Local Authorities in our region have committed to decarbonisation targets which are more ambitious than the government's 2050 net zero emissions target enshrined in law. Both Cumbria County Council and Greater Manchester Combined Authority (GMCA) have announced their intention to reach net zero carbon by 2037 and 2038 respectively. This is in addition to other county and borough councils in our region declaring a climate emergency as part of their action to avert a climate crisis. These moves by our regional governing bodies and the steps already being taken by local organisations are clear indications of the commitment to accelerated decarbonisation. However, we cannot be as certain of the rate and extent of local transformation without central government's funding and ability to change policies to influence the transition. For this reason, our Best View Development Plan presented in NDP considers developments contained within our DFES that have strong supporting evidence from LA and have UK government backing and secured funding. This enables us to ensure a holistic approach and avoid piecemeal network development as described in section 3.3.2.

Our published Network Development Plan is our best view of what we expect will be required during the coming 10-year period up to 2030/31 and therefore in advance of when decisions are usually made. Therefore, project development plans are regularly reappraised on an annual basis using the most up to date actual conditions and forecasts to ensure they requirements are still valid and the solution most efficient. Investment plans are scrutinised as part of this process to assess whether they still provide the optimal way forward and will deliver the necessary benefits at the required time. This way we ensure that our plans flex to reflect the changing energy landscape and network requirements. As with all capacity shortfalls, the market is tested at that time to determine if a flexible service can be obtained to provide a solution and the associated cost, so that a fair comprehensive cost benefit analysis can be used to compare with more traditional asset-based interventions to establish the most efficient solution to be taken forward.