WESTERN POWER DISTRIBUTION

Serving the Midlands, South West and Wales

Business Plan 2023 - 2028

SA-06a Supplementary Annexe Load Related Expenditure

December 2021

SA-06a Load related expenditure Contents

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1. Introduction

1.1. The next regulatory price control review period, known as RIIO-ED2 is a five year period and is the second for electricity distribution to be determined using Ofgem's Revenue = Incentives, Innovation and Outputs framework. This price control period runs from 1st April 2023 to 31st March 2028.

1.2. Western Power Distribution (WPD) is required to submit a 200 page Business Plan document, supplementary annexes, detailed cost tables, financial information and a range of other documents which form our submission under RIIO-ED2 to Ofgem, which will be used to determine allowed revenues for the price control period.

1.3. Our RIIO-ED2 Business Plan has been produced and compiled in line with the following key principles:

- Co-created with our stakeholders and supported by them.
- Our plan – 'prepared with our stakeholders for delivery by us'.
- Aligned with WPD's purpose and values.
- Affordable for all of our customers.
- Sustainable and will enable net zero before 2050.

1.4. Everything in our Business Plan submission is driven to achieve the following four strategic outcomes for customers:

1. Sustainability
Lead the drive to net zero as early as possible.

2. Connectability
Customers can easily connect their electric vehicles, heat pumps and renewable generation.

3. Vulnerability
First class vulnerable customer support programme where everyone benefits in a smart future.

4. Affordability
Maintain excellent customer service, safety and network performance and transform the energy grid for future generations, while keeping bills broadly flat.

1.5. The diagram below (figure SA-06a.0) shows the structure of the full Business Plan submission with the red box showing where this document fits into the overall suite of documents.

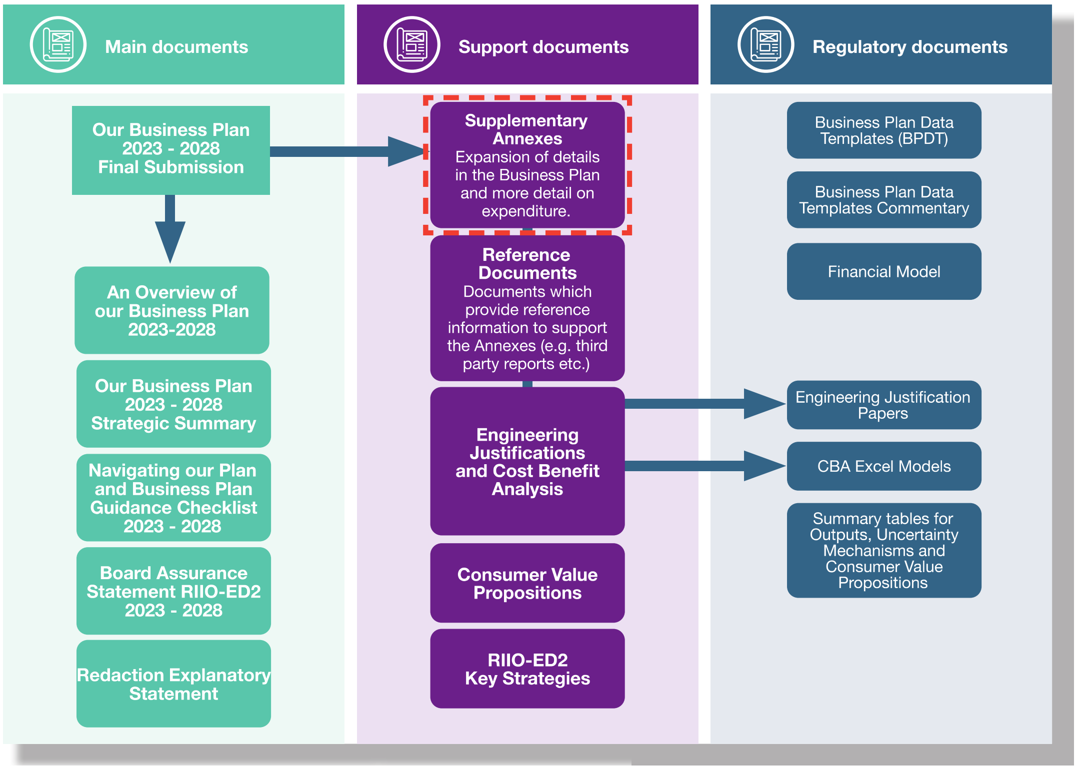

Figure SA-06a.0 Business Plan submission structure

1.6. This document is a Supplementary Annex to Chapter 6 of WPD's RIIO-ED2 Business Plan document. Annex 6a: Load related expenditure details the expenditure plans we will deliver through the period from 2023 to 2028, for the four WPD distribution licences of West Midlands, East Midlands, South Wales and South West.

1.7. We appreciate that the readers of the WPD RIIO-ED2 Business Plan suite of documents will range from regulatory experts and well informed stakeholders through to new customers who may have had little previous knowledge of WPD.

1.8. This document is aimed at readers who require a more detailed understanding of load related expenditure.

1.9. This document is subdivided into the following sections:

Section	Title	Content
2	Load Related Expenditure	This section sets out in greater detail our methodology underpinning load related investment plans across WPD's four licence areas.
3	Strategic Vision	This section outlines our strategic vision for load related expenditure and development of the network.
4	Forecasting	This section provides a detailed description of our forecasting process and outlines how the Distribution Future Energy Scenarios are used to create WPD Best View forecast of future network loads.
5	Network impact assessment	This section describes how the forecast is used to assess what the impact on the electricity network is as a result of the forecasted load.
6	Optioneering	This section shows the evaluation which is undertaken to alleviate the capacity issue including the use of flexibility and conventional reinforcement.
7	Load Related Investment Plan	This section details the load related investment plan and information regarding our view on the method of funding that investment.
8	Load Related expenditure summary	This section provides an overview of the high level expenditure for each investment categories across the WPD regions and the individual named Engineering Justification Papers for all projects over £1 million
9	Appendices	A number of appendices with additional information or containing links to supporting reports and strategies.

2. Load related expenditure

2.1. RIIO-ED2 will be a period of significant change as the UK works towards achieving a net zero carbon future – and WPD plays a critical role in leading the way. Our expenditure plans reflect this challenge to deliver a network which meets future energy requirements, as well as ensuring we continue to deliver industry-leading service to customers at an efficient cost, while protecting our most vulnerable customers and tackling fuel poverty.

2.2. This section sets out in greater detail our methodology underpinning load related investment plans from the development of forecasts, through network assessment and to decision making across WPD's four licence areas; West Midlands, East Midlands, South Wales and South West.

2.3. Load related investment is expenditure incurred when providing additional capacity on the network to facilitate new connections as well as load growth. This covers both demand and generation. Load related reinforcement investment falls into four categories: connections, general reinforcement, fault level and new transmission capacity charges. The annual expenditure in all four category areas is expected to increase during RIIO-ED2, despite a significant increase in the use of flexibility to offset traditional reinforcement.

2.4. Reinforcement based on WPD's Best View will increase from 8% of Totex as an average in RIIO-ED1, to 14% throughout RIIO-ED2. The main reason for higher load related expenditure is the government's 2050 net zero target, which is driving significant growth in Low Carbon Technologies (LCTs). This is exacerbated by the ambitious local development plans of many local authorities in our region which feature commercial, industrial and housing developments. Investment through the price control could exceed the Best View and WPD is proposing additional mechanisms to achieve this.

2.5. A high level summary of our load related planning methodology is shown in figure SA-06a.1 below. It shows the whole end-to-end process from forecasting to the load related investment plan that will be expounded in this document.

Figure SA-06a.1 High level load related investment planning methodology

3. Strategic vision

3.1. The high level load related investment planning methodology ensures that WPD has a transparent framework for identifying and selecting the optimal investment plan. In addition to the high level methodology, our strategic vision defines the principles to ensure the load related expenditure plan does not act as a barrier to net zero targets and delivers an efficient plan in the context of uncertainty. We are an adaptable and dynamic business, and our plan reflects this – allowing us to react and act in the face of an uncertain climate.

Periodic refresh of input data

- WPD recognises the levels of uncertainty which are present in the range of futures as the UK transitions to a net zero future. In particular how much of a role electrification has to play in the decarbonisation of sectors including transport and domestic heat will result in a different impact on electricity distribution networks.
- As a result it is crucial to ensure that any load related expenditure plan is created using input data which closely reflects local and national policies and relevant data where available. The WPD strategic vision is to periodically assess and refresh our input data for forecasting to ensure that the load related investment plan is up to date.

Developing capability

- The distribution network continues to become more complex and active due to the decentralisation of the generation mix across the UK and more opportunities for customers to alter energy consumption and participate in flexibility markets. As a result, the analysis tools and techniques required for network impact assessment also require development. This is to ensure that the network impact assessment captures the most onerous network loading conditions, essential to the coordinated, economic and efficient design of the network.
- During the RIIO-ED1 period WPD developed automated network analysis tools and techniques to investigate how growth projections will affect the design and operation of the distribution network. The tools allowed WPD to be the first Distribution Network Operator (DNO) to publish a 'Shaping Subtransmission' document using detailed contingency analysis to identify areas where investment may be required.
- WPD strategic vision is to continue to develop our capability to undertake forecasting and network impact assessment. For forecasting activities this includes incorporating improved techniques to better understand the composition and coincidence of demand and generation customers to more accurately study the credible onerous network loading conditions. For network impact assessment activities this includes further automating analysis tools and techniques to more comprehensively study our networks.

Keeping an eye on strategic investment

- WPD acknowledge the challenge to deliver sufficient, timely capacity to support decarbonisation, while protecting customers from unnecessary or inefficient investment. The Distribution Future Energy Scenarios (DFES) analyses multiple credible pathways for how the net zero targets could impact distribution networks. The subsequent automated analysis for the network impact assessment allows identification of wider strategic works that may not be highlighted by routine localised system analysis.
- These activities ensure that the methodology monitors whether any wider strategic investment could be required to support decarbonisation plans. Early identification of the potential for strategic investment will allow WPD to account for whole system outcomes, which will in turn lead to better investment outcomes for the networks and for regional stakeholders.

- Our strategic vision is to use a proactive approach to scenario based forecasting and automated network impact assessment. In doing so any wider strategic works can be identified and relevant stakeholders engaged early to ensure a coordinated whole system approach is considered.

Process transparency

- Throughout the RIIO-ED1 period we have developed capability in strategic investment planning. Figure SA-06a.2 outlines the current WPD strategic investment planning process and how the forecasting activity permeates throughout all aspects of the business including regulatory reporting. This ensures consistency in reporting of forecast information across all business areas.

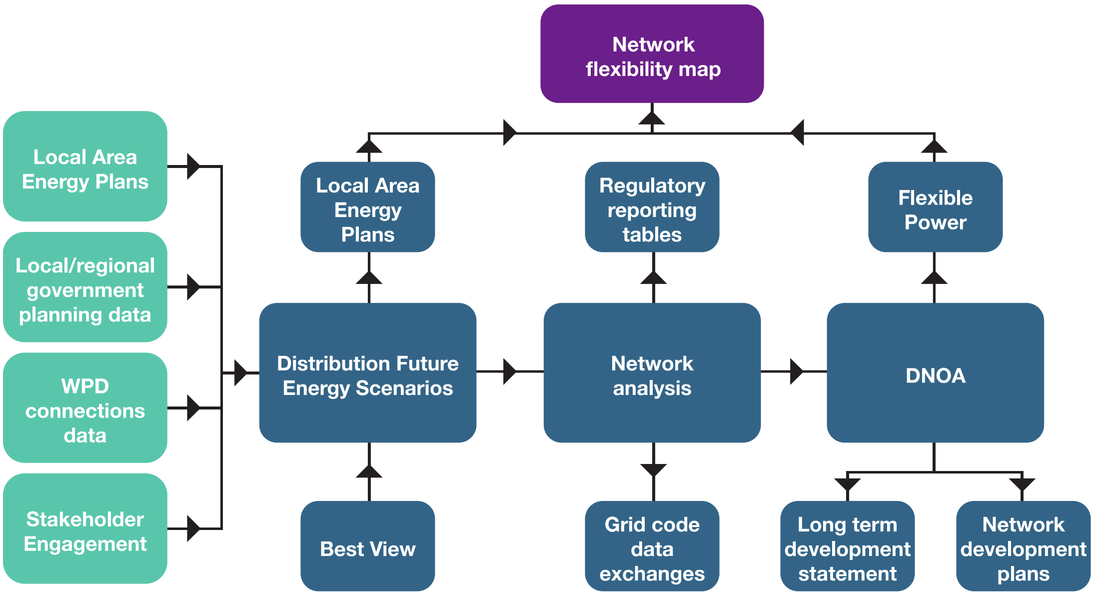

Figure SA-06a.2 A flow chart describing the existing WPD process for investment planning

- Throughout the RIIO-ED2 period we expect the Network Development Plan (NDP) to play an important role in identifying the high value schemes for inclusion in our load related investment plan. This utilises any periodically refreshed input data and ensures the load related investment plan reflects the requirements of our customers. Publication of our data, methodology and key assumptions throughout all steps of the load related investment planning process ensures transparency and robustly justify any changes in our expected load related expenditure from the RIIO-ED2 plan.

Indicators to measure the success of the strategic vision

- WPD plan to use a series of indicators to monitor whether the strategic vision successfully achieves the strategic outcomes identified. Figure SA-06a.3 outlines the specific indicators and how they will be measured.

Strategic Vision	Key Performance Indicator
Periodic refresh of input data	Regularly update our suite of load related expenditure planning documents, including Distribution Future Energy Scenarios, Network Development Plans and Distribution Network Options Assessment. All reports will be published on our website. Data and assumptions will be published on our Connected Data Portal, aligning with the core commitment to improve the accessibility and usefulness of data.
Developing capability	Include a limitations and developments section in each publication related to the load related expenditure plan. This will outline how assumptions have been incrementally improved and quantify the impact on study outputs.
Keeping an eye on strategic investment	Any large scale strategic works identified will be assessed for suitability for Regional Development Programmes. Whole system interactions will be recorded on the Whole System Coordination Register.
Process transparency	Any changes in investment projects anticipated to be undertaken in the Network Development Plan window will be assessed for impact and the associated changes to forecasts, assumptions and delivery plans will be described. An increased accuracy of forecasts and modelling capability will be reflected in fewer changes to shorter-term plans.

Figure SA-06a.3 A table describing indicators for measuring success of strategic vision

4. Forecasting

4.1. The first step in WPD's load related planning methodology is establishing a forecast of future network loads across each of our four licence areas. Since 2015, WPD has been undertaking scenario planning work through Distribution Future Energy Scenarios reports, updating these on a two-yearly cycle to provide a forward looking 10 year window of potential low carbon technology uptakes. From 2020 a full suite of DFES documents have been produced annually which consider a 30 year horizon to 2050.

4.2. The DFES projections are aligned to a common scenario framework, to allow for comparison between DFES publications from different distribution network operators and the Electricity System Operator Future Energy Scenarios (FES) publication. The scenarios used as part of the 2020 Future Energy Scenarios and Committee for Climate Change 6th Carbon Budget are included in this annexe to allow for comparison to the DFES projections.

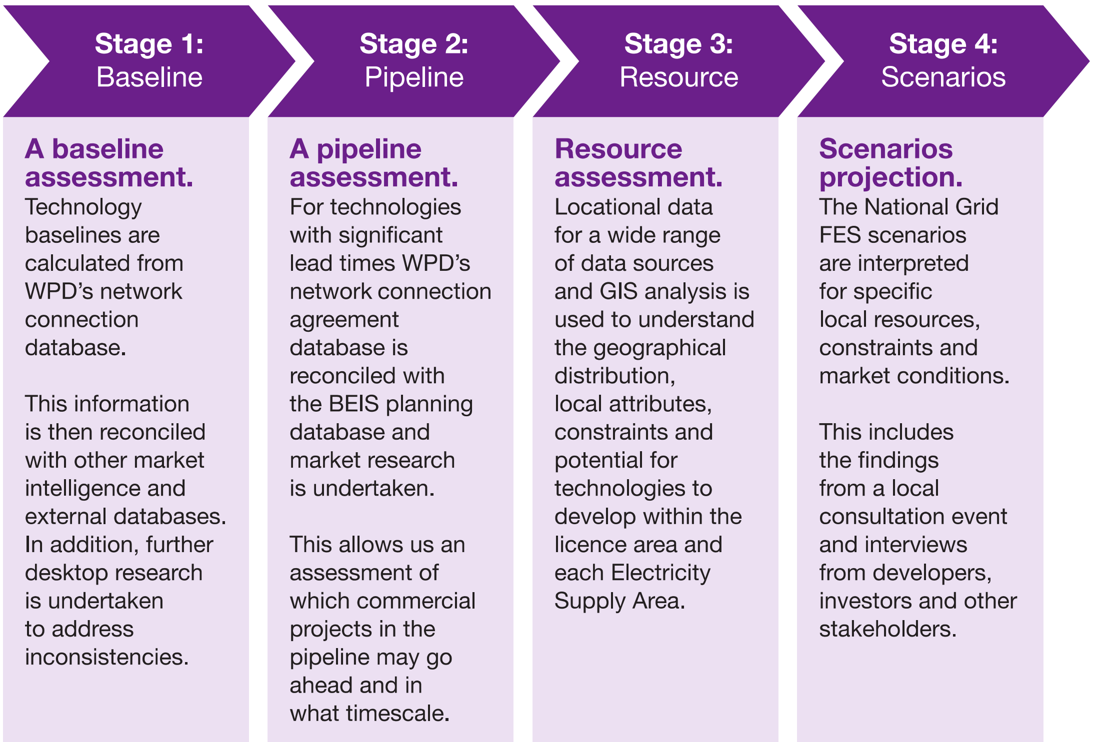

Figure SA-06a.4 A flow chart describing the 4 main stages of the DFES process

4.3. During the DFES process, different demand, storage and generation technologies are assessed for their potential growth under each scenario under the common framework. A list of the technologies covered in the DFES process is included in the DFES: Customer Behaviour Profiles and Assumptions Report. The process is carried out across four main stages as outlined in figure SA-06a.4.

4.4. During this process, WPD invites all local authority stakeholders covered by the WPD area to work with WPD to build a joined-up energy plan. WPD sought the following data from local authorities:

- General data based around a local energy strategy, declaration of a climate emergency and setting a target date to reach net zero.
- Availability and comparison of data sets.

- Technology projections for electric vehicles, heat pumps, new industrial, commercial and domestic developments, generation including solar, wind and battery storage.

The feedback from local authorities is used to refine the allocation of growth projections across the WPD licence areas, making them more representative of local requirements. WPD plans to continue this interaction with local authorities every year to feed into the annual review of WPD's DFES scenarios.

4.5. In addition to stakeholder engagement with local authorities as part of the DFES, other industry experts are invited to input on the expected uptake of different technologies. These include community energy groups, energy industry and academia stakeholders. An event is run for each licence area to obtain quantitative feedback, the results of which are published in the DFES: Stakeholder Consultation Summary Report. These reports outline how WPD responds to comments and incorporates feedback received into the DFES projections.

4.6. The output of the DFES process is a data set of growth projections for each technology, scenario and year at an Electricity Supply Area (ESA) level. This data is published on an interactive DFES map, called a heat map, on the WPD website. The heat map in figure SA-06a.5 below shows the expected growth of non-hybrid heat pumps under the 'Leading the Way' scenario in the West Midlands. This illustrates how much LCT uptake is expected to vary on a locational basis.

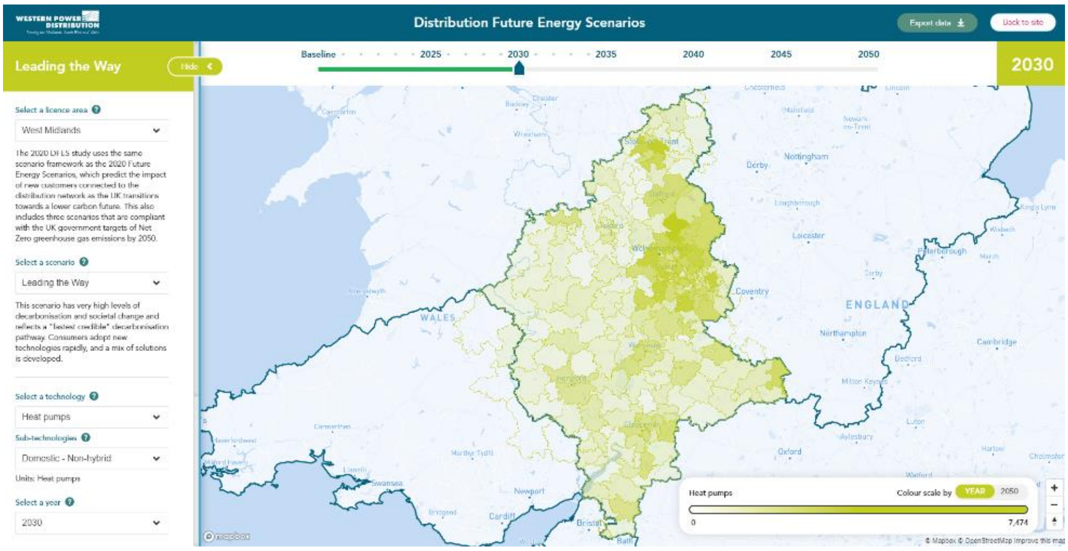

Figure SA-06a.5 A heat map of the number of non-hybrid heat pumps per Electricity Supply Area in the West Midlands under the Leading the Way scenario

4.7. The next step in the DFES process is to account for customer behaviour to the projected volumes. This is used to take into consideration the expected demand and generation profiles of new and existing customers connected to the distribution network. To ensure the credible edge cases for network impact assessment are identified, this complex analysis includes aspects of pricing-led Demand Side Response (DSR) and how we expect customer behaviour to change over time. The output of this process is the DFES: Customer Behaviour Profiles and Assumptions Report of load profiles suitable for strategic analysis of the distribution network included in Appendix A02 of this report.

4.8. It is assumed that some of the projected growth will be offset by increases in efficiency. These will arise from a combination of a gradual decrease in the underlying demand and the assumption that new demand connecting to the network will be more efficient than the existing stock. These energy efficiency figures are obtained by extrapolation of historic energy consumption across WPD's licence areas.

4.9. An allowance is also made for pricing-led DSR. This assumes that market-led price signals (not initiated by WPD) will be utilised to avoid electricity usage at times of peak demand.

4.10. The effects of efficiency and pricing-led DSR on the future demand predicted in the WPD Best View scenario are illustrated in figure SA-06a.6. These impacts are summarised for each technology considered as part of the DFES process in the DFES: Customer Behaviour Profiles and Assumptions Report, which outlines how the customer demand across the network is assumed to change over time.

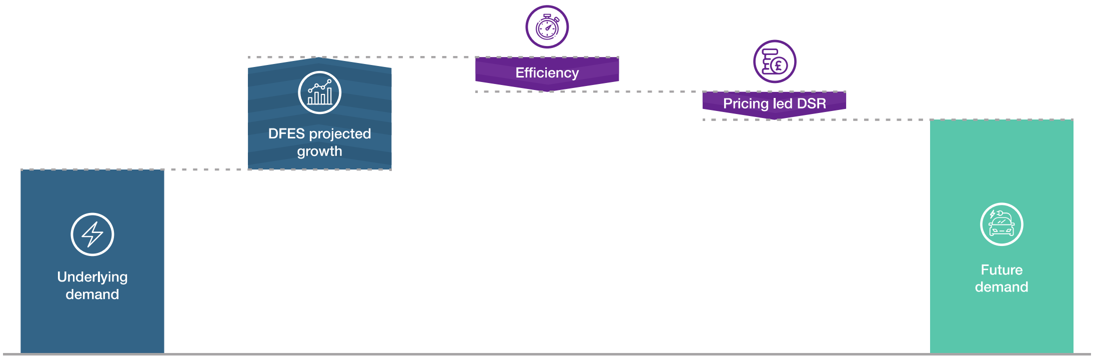

Figure SA-06a.6 The effect of efficiency and pricing led DSR on the demand for the WPD Best View growth scenario

4.11. The customer behaviour profiles used as part of the network impact assessment must be applied with reference to the intended purposes of the network analysis activity. For RIIO-ED2 investment planning purposes, the starting load assumptions were applied to the relevant voltage level to ensure the most credible set of forecast demand and generation load sets were applied. For Extra High Voltage (EHV) network analysis, starting load assumptions are derived from observed monitoring data as part of an engineering load survey. The starting load assumptions are chosen to be reflective of the credible edge case applicable to the voltage level and purpose of network analysis.

4.12. In addition to the four base DFES scenarios, a fifth scenario is created which amalgamates the assumptions of the four base scenarios. The WPD Best View is not a single central outlook, but instead is derived from bespoke assessment of Local Area Energy Plans (LAEPs) and local delivery capability to enable WPD to assign one of the DFES scenarios for each local authority and hence all substations within that area.

4.13. WPD believes that where DNO LCT volume forecasts align with LAEP forecasts, this should be regarded as highly certain, as long as that LAEP can demonstrate that it represents the expectations of local stakeholders, that the requirements are reasonable and built up from quality evidence of need and that there is a competent plan for delivery.

4.14. The WPD Best View scenario is created using an iterative process where DFES data and the WPD Best View from the previous year are used to support stakeholder and local area engagement, which then allows the quality of Local Area Energy Plans to be assessed using criteria derived from the Ofgem LAEP Best Practice checklist to gauge the ambition, engagement and deliverability. This process followed is outlined in figure SA-06a.7.

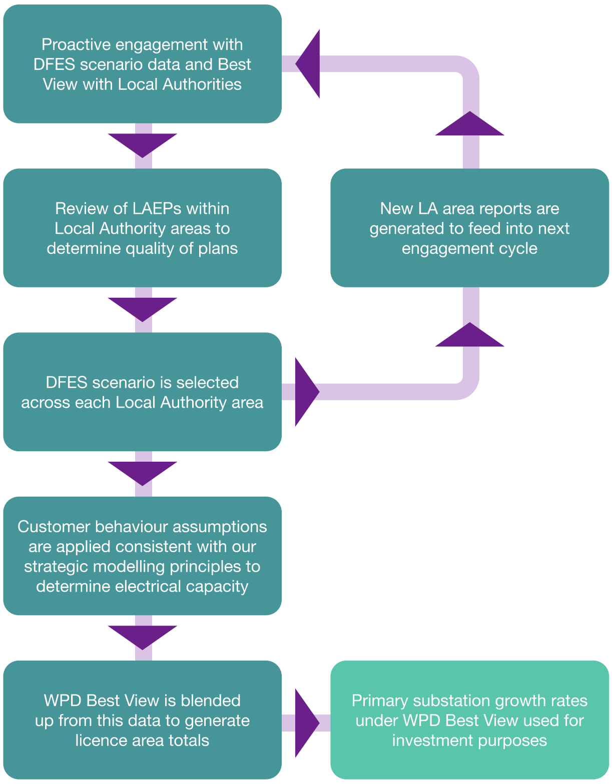

Figure SA-06a.7 A flowchart showing the iterative process used to create the DFES each year through stakeholder and local area engagement

4.15. The assessment is carried out by WPD's senior regional managers, scoring against a criteria matrix so that Local Area specific DFES scenarios can be selected. The DFES scenario is chosen by closely comparing the ambition of the planned volumes across all technology types within the area, and then further ranked on how close this ambition is likely to be to the needs of stakeholders (engagement completed), the accuracy of the modelling and the capability of the area to deliver. A single DFES scenario is currently chosen to approximately represent all technologies, but there is scope in the future for differentiation between expected uptakes of technologies to also be simultaneously assessed. Figure SA-06a.8 outlines a map showing how different scenarios are assigned to the different local authority areas.

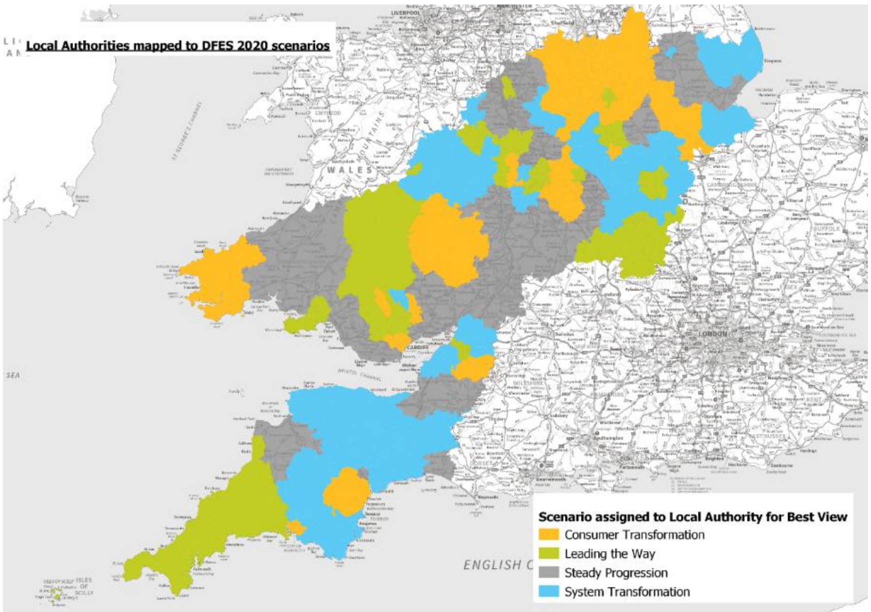

Figure SA-06a.8 A map showing how different scenarios are assigned to different local authority areas across WPD's 4 licence areas

Alignment to national level scenario forecasts

4.16. Before the WPD Best View scenario is finalised, the licence area totals are checked against national ambition to ensure WPD targets are aligned to deliver governmental policy. The following sections outline how the WPD Best View relates to different national level scenario forecasts, including the 2020 Future Energy Scenarios and the scenarios used as part of the 6th Carbon Budget produced by the Committee for Climate Change (CCC).

4.17. Assumptions have been made in order to compare the national level forecasts (apportioned to the WPD licence areas) to the WPD Best View totals. Depending on the metric for comparison, the apportionment methodology uses the existing split of customer numbers in Great Britain supplied by WPD or the existing split of total GB energy consumption within the WPD licence areas. The CCC 6th Carbon Budget scenarios are created for the United Kingdom, therefore the totals for Northern Ireland are required to be subtracted from the totals provided in the Business Plan Guidance to subsequently be compared to the WPD Best View totals. In addition, some of the projections made in the Future Energy Scenarios consider some, but not all, of the customers which Distribution Network Operators when accounting for future network usage projections (for example, with the comparison of electric vehicle penetration).

4.18. Heat pump volumes are summarised in figure SA-06a.9 for the WPD Best View scenario and the net zero compliant scenarios from the FES 2020 and CCC 6th Carbon Budget publications. The totals provided are for the year 2030.

Data Source	Scenario	2030 total apportioned to WPD licence areas (millions)[1]	2030 WPD Best View total (millions)
NGESO FES 2020[2]	*Leading the Way*	1.987	**1.202**
	Consumer Transformation	1.559	
	System Transformation	0.468	
CCC 6th Carbon Budget[3]	*Balanced Net Zero Pathway*	1.385	
	Headwinds	1.048	
	Tailwinds	1.289	
	Widespread Engagement	1.495	
	Widespread Innovation	1.347	

Figure SA-06a.9 Heat pump volumes for 2030 for the WPD Best View, net zero compliant scenarios from the FES 2020 and the CCC 6th Carbon Budget

[1] Total provided in BPG for GB multiplied by proportion of existing total customers in UK are supplied by WPD as taken from RIIO-ED1 Network Performance Summary 2019-20 Supplementary Data File. For CCC scenarios, this required subtraction of the Northern Ireland totals from UK totals provided in BPG to allow for apportionment factor to be used for WPD licence areas.

[2] Please note only the three ‘net zero by 2050’ compliant scenarios were selected for Business Plan comparison in guidance. Totals provided in Business Plan Guidance are for Great Britain.

[3] Please note totals provided in Business Plan Guidance for CCC totals are for United Kingdom.

4.19. The heat pump volumes have been disaggregated to estimate the total heat pump projections within WPD licence areas using the proportional number of customers in Great Britain supplied by WPD. The heat pump volumes summary table demonstrates that the WPD Best View scenario volumes sit within the range of potential heat pump volume projections as noted in the FES and CCC scenarios. The graph in figure SA-06a.10 outlines the heat pump projected volumes for all years from 2020 to 2030 for the scenarios considered. The DFES: Technology Summary reports outline how heat pump projections in each licence area differ from the national average due to the existing building stock and prevalence of off-gas housing.

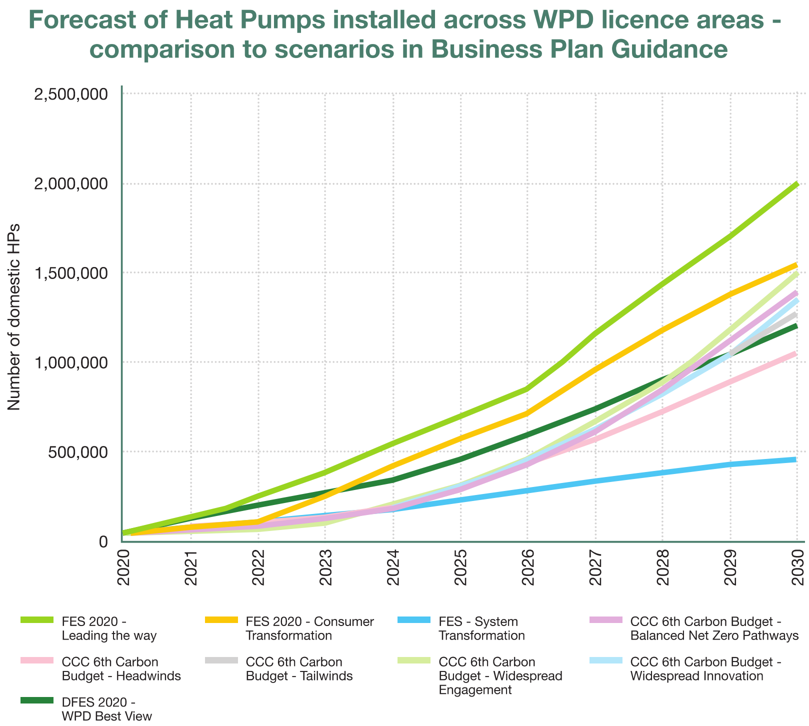

Figure SA-06a.10 A graph of the heat pump volume projections for all scenarios considered from 2020 to 2030

4.20. Projected energy consumption from additional heat pumps is summarised in figure SA-06a.11 for the WPD Best View scenario and the net zero compliant scenarios from the FES 2020 and CCC 6th Carbon Budget publications. The totals provided are for the year 2030.

Data Source	Scenario	2030 total apportioned to WPD licence areas (TWh)[4]	2030 WPD Best View total (TWh)
NGESO FES 2020[5]	*Leading the Way*	6.41	**4.04**
	Consumer Transformation	5.61	
	System Transformation	1.60	
CCC 6th Carbon Budget[6]	*Balanced Net Zero Pathway*	2.60	
	Headwinds	0.85	
	Tailwinds	2.50	
	Widespread Engagement	2.69	
	Widespread Innovation	3.35	

Figure SA-06a.11 Heat pump energy consumption for 2030 for the WPD Best View, net zero compliant scenarios from the FES 2020 and the CCC 6th Carbon Budget

4.21. The heat pump energy total is disaggregated to estimate the total within WPD licence areas using the proportional energy consumption in Great Britain supplied by WPD. The heat pump energy consumption summary table demonstrates that the WPD Best View scenario volumes sit within the range of potential heat pump energy projections as noted in the FES and CCC scenarios.

4.22. Electric vehicle volumes are summarised in SA-06a.12 for the WPD Best View scenario and the net zero compliant scenarios from the FES 2020 and CCC 6th Carbon Budget publications. The totals provided are for the year 2030.

[4] Total provided in BPG for GB multiplied by proportion of existing energy consumption in GB are supplied by WPD as taken from RIIO-ED1 Network Performance Summary 2019-20 Supplementary Data File. For CCC scenarios, this required subtraction of the Northern Ireland totals from UK totals provided in BPG to allow for apportionment factor to be used for WPD licence areas for the 'electricity demand for low carbon heat in existing buildings'.

[5] Please note only the three FES 'net zero by 2050' compliant scenarios were selected for Business Plan comparison in guidance. Totals provided in Business Plan Guidance are for Great Britain.

[6] Please note totals provided in Business Plan Guidance for CCC totals are for United Kingdom.

Data Source	Scenario	2030 total for to WPD licence areas (millions)[7]	2030 WPD Best View total for direct comparison to Business Plan Guidance (millions)[8,9]	2030 WPD Best View total (millions)[10]
NGESO FES 2020[11]	*Leading the Way*	3.085	**2.475**	**3.199**
	Consumer Transformation	2.945		
	System Transformation	1.269		
CCC 6th Carbon Budget[12]	*Balanced Net Zero Pathway*	4.566	**3.192**	
	Headwinds	3.650		
	Tailwinds	4.489		
	Widespread Engagement	4.735		
	Widespread Innovation	4.505		

Figure SA-06a.12 Electric vehicle volumes for 2030 for the WPD Best View, net zero compliant scenarios from the FES 2020 and the CCC 6th Carbon Budget

4.23. The electric vehicle volumes have been disaggregated to estimate the total electric vehicle projections within WPD licence areas using the proportional number of customers in Great Britain supplied by WPD. The FES totals provided by Ofgem in the Business Plan Guidance relate to the number of pure electric cars registered in GB. The CCC totals in the Business Plan Guidance relate to the number of electric vehicles (excluding Heavy Goods Vehicles) in the United Kingdom.

4.24. As a result, the electric vehicles projections do not allow for direct comparison between scenarios. The WPD Best View totals which are used in the network impact assessment must encompass all types of electric vehicle in order for WPD to design a coordinated, economic and efficient network for the use of all customers. The DFES Technology Summary reports outline how electric vehicle projections in each licence area differ from the national average due to measures such as affluence, rurality, existing vehicle baselines and the distribution of on and off street parking.

4.25. Projected energy consumption from additional electric vehicles is summarised in figure SA-06a.13 for the WPD Best View scenario and the net zero compliant scenarios from the FES 2020 and CCC 6th Carbon Budget publications. The totals provided are for the year 2030.

[7] Total provided in BPG for GB multiplied by proportion of existing total customers in UK are supplied by WPD as taken from RIIO-ED1 Network Performance Summary 2019-20 Supplementary Data File. For CCC scenarios, this required subtraction of the Northern Ireland totals from UK totals provided in BPG to allow for apportionment factor to be used for WPD licence areas.

[8] CCC total includes all pure electric and hybrid vehicles (except HGV and bus/coach). WPD Best View totals provided to allow for direct comparison to CCC totals.

[9] FES total include only battery electric cars in GB. WPD Best View totals provided to allow for direct comparison to FES totals.

[10] WPD Best View used for RIIO-ED2 investment planning processes uses a total of all electric vehicles (including HGV and bus/coach), as the network will be designed to accommodate all potential electrification of transport.

[11] Please note only the three FES ‘net zero by 2050’ compliant scenarios were selected for Business Plan comparison in guidance. Totals provided in Business Plan Guidance are for Great Britain.

[12] Please note totals provided in Business Plan Guidance for CCC totals are for United Kingdom.

Data Source	Scenario	2030 total for to WPD licence areas (millions)[13]	2030 WPD Best View total (TWh)
NGESO FES 2020[14]	*Leading the Way*	8.21	**7.69**
	Consumer Transformation	7.21	
	System Transformation	4.25	
CCC 6th Carbon Budget[15]	*Balanced Net Zero Pathway*	10.00	
	Headwinds	8.59	
	Tailwinds	9.13	
	Widespread Engagement	9.16	
	Widespread Innovation	10.63	

Figure SA-06a.13: Electric vehicle energy consumption for 2030 for the WPD Best View, net zero compliant scenarios from the FES 2020 and the CCC 6th Carbon Budget

4.26. The electric vehicle energy total is disaggregated to estimate the total within WPD licence areas using the proportional energy consumption in Great Britain supplied by WPD. The electric vehicle energy consumption summary table demonstrates that the WPD Best View scenario volumes sit within the range of potential electric vehicle energy projections as noted in the FES and CCC scenarios.

[13] Total provided in BPG for GB multiplied by proportion of existing total customers in UK are supplied by WPD as taken from RIIO-ED1 Network Performance Summary 2019-20 Supplementary Data File. For CCC scenarios, this required subtraction of the Northern Ireland totals from UK totals provided in BPG to allow for apportionment factor to be used for WPD licence areas.

[14] Please note only the three FES 'net zero by 2050' compliant scenarios were selected for Business Plan comparison in guidance. Totals provided in Business Plan Guidance are for Great Britain.

[15] Please note totals provided in Business Plan Guidance for CCC totals are for United Kingdom.

4.27. Total electrical energy consumption is, summarised in figure SA-06a.14, for the WPD Best View scenario and the net zero compliant scenarios from the FES 2020 and CCC 6th Carbon Budget publications. The totals provided are for the year 2030.

Data Source	Scenario	2030 total apportioned to WPD licence areas (TWh)[16,17]	2030 WPD Best View total (TWh)
NGESO FES 2020[18]	*Leading the Way*	74.476	**84.484**
	Consumer Transformation	80.125	
	System Transformation	75.409	
CCC 6th Carbon Budget[19]	*Balanced Net Zero Pathway*	93.893	
	Headwinds	91.296	
	Tailwinds	96.737	
	Widespread Engagement	91.748	
	Widespread Innovation	96.596	

Figure SA-06a.14 Total energy consumption for 2030 for the WPD Best View, net zero compliant scenarios from the FES 2020 and the CCC 6th Carbon Budget

[16] Please note total energy consumption referred to as total customer demand, excluding network losses. Please note slight discrepancies in the baseline data may be due to different baseline snapshots.

[17] Total provided in BPG for GB multiplied by proportion of existing energy consumption in GB are supplied by WPD as taken from RIIO-ED1 Network Performance Summary 2019-20 Supplementary Data File. For CCC scenarios, this required subtraction of the Northern Ireland totals from UK totals provided in BPG to allow for apportionment factor to be used for WPD licence areas.

[18] Please note only the three FES 'net zero by 2050' compliant scenarios were selected for Business Plan comparison in guidance. Totals provided in Business Plan Guidance are for Great Britain.

[19] Please note totals provided in Business Plan Guidance for CCC totals are for United Kingdom.

4.28. The energy consumption forecast has been disaggregated to estimate the total electrical energy demand within WPD licence areas using the proportional share of energy consumption in Great Britain supplied by WPD. The total energy consumption summary table demonstrates that the WPD Best View scenario volumes sit within the range of potential projections as noted in the FES and CCC scenarios. The graph in figure SA-06a.15 below outlines the projected energy consumption for all years from 2020 to 2030 for the scenarios considered.

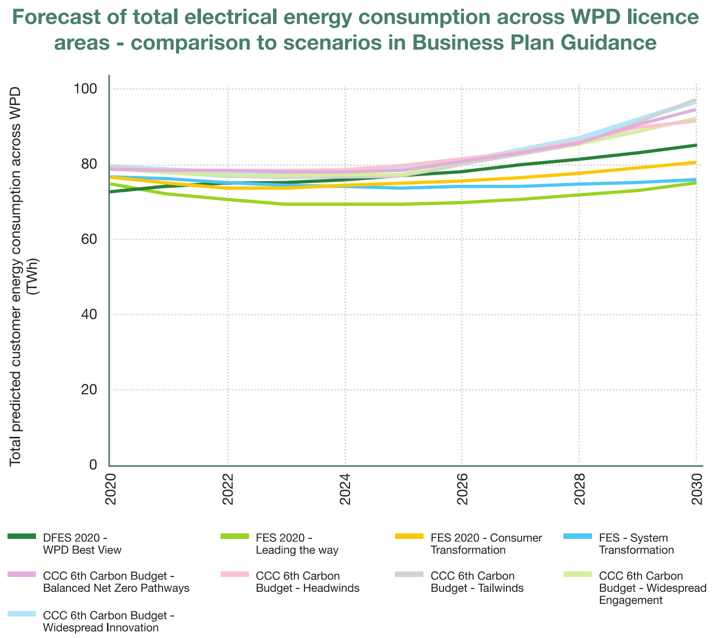

Figure SA-06a.15 A graph of the projected energy consumption for all of the scenarios considered from 2020 to 2030

4.29. The WPD Best View energy projections align well with the FES and CCC scenarios in the period up to 2030. In the early 2020s, the WPD Best View includes a small increase in the total energy consumption, at a greater rate than the range outlined in the FES and CCC scenarios. This is due to lower assumptions for the expected decrease in existing demand due to energy efficiency measures than those used in the FES and CCC scenarios.

4.30. Examination of the historic energy consumption during the period from 2011 to 2020 shows that the energy reduction across WPD at the beginning of the decade was greater than the national average, but has reduced through time and now is decreasing at a lower rate than the UK average and at a rate much lower than the near term FES and CCC scenario projections. This is illustrated in figure SA-06a.16 below. This trend is attributed to the WPD licence areas being further along the energy transition, which is evidenced by the greater than average adoption of photovoltaic installations and other distributed energy resources and LCTs.

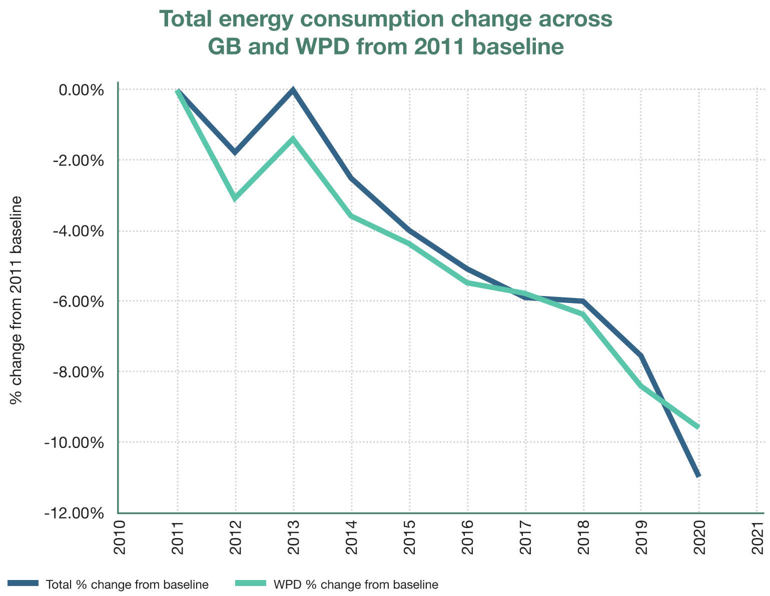

Figure SA-06a.16 A graph of the total energy consumption change across GB and WPD from a 2011 baseline level

4.31. Comparison of peak demand forecasts is difficult, due to the different levels of diversity used when designing the distribution network and national level system demand peaks. The peak demand figures presented in the RIIO-ED2 Business Plan Guidance document for comparison to the Future Energy Scenarios only accounted for the projected contribution to system peak demand from domestic customers. When assessing the investment required on the network for peak demand conditions the contribution towards peak demand from all customers must be considered. Figure SA-06a.17 shows the breakdown of the WPD Best View sum of licence area peak demand to 2030. This contains all of the expected growth in demand due to the electrification of heat and transport, in addition to new domestic and non-domestic customers expected to connect to the network.

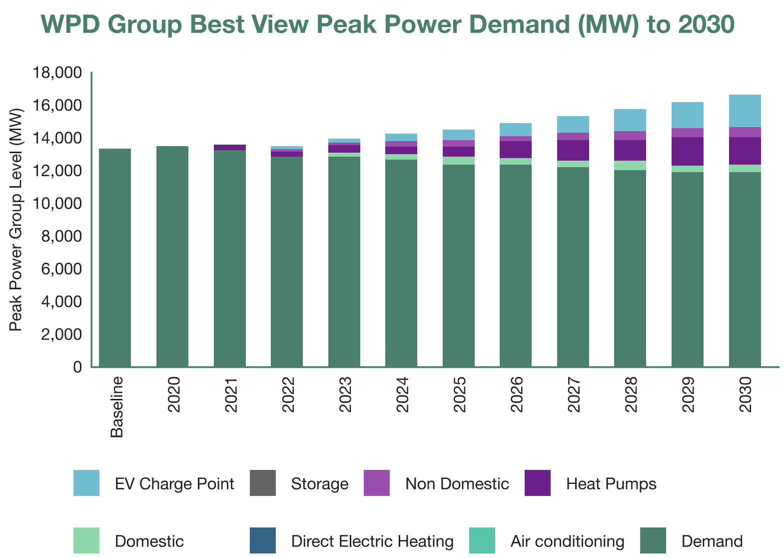

Figure SA-06a.17 A graph of the total WPD group (sum of licence area) peak demand (MW) for the WPD Best View scenario out to 2050

Load Related Expenditure Business Plan Data Table commentary

4.32. Forecasts for the energy consumption (units distributed) and customer numbers are provided as part of the RIIO-ED2 Business Plan Data Tables. The tables outline the expected change across the four WPD Distribution Future Energy Scenarios, the WPD Best View and the ‘high’ and ‘low’ scenarios. This is subcategorised by the energy consumption or customer numbers for domestic and non-domestic consumers.

4.33. The historic energy consumption is provided for each licence area, split between the domestic and non-domestic usage for each year during the RIIO-ED1 period. The energy forecasts are derived from DFES modelling out to 2050 and account for all technologies expected to utilise the WPD network in future years. This shows a shift towards a greater proportion of total energy consumption by domestic consumers which is primarily driven by an increase in household energy consumption for the electrification of heat and transport.

4.34. The historic customer numbers are provided for each licence area, the split between the domestic and non-domestic customer numbers uses a historic average observed for WPD customers across the RIIO-ED1 period. The customer number forecasts are derived from DFES modelling out to 2050 and accounts for the growth in demand which would result in additional customers. The proportional split between domestic and non-domestic customers is assumed to stay constant for all future years.

4.35. In addition to the DFES and WPD Best view scenarios presented in the Load Related Expenditure Business Plan Data Tables, a ‘high’ and ‘low’ scenario are also provided. The high scenario relates to the scenario where the projected energy consumption is highest in each year. This closely follows the scenario where the highest level of investment is required for customers to help the UK attain the net zero targets. Conversely, the low scenario relates to the net zero compliant scenario where the projected energy consumption is lowest in each year.

4.36. The Load Related Expenditure Business Plan Data Tables also include a forecast for the cost of load related expenditure and total expenditure (totex) out to 2050 for all scenarios. Load related expenditure is calculated relative to the energy consumption forecasts and is benchmarked against the projected cost forecasts throughout the RIIO-ED2 period. The cost projections are higher in the RIIO-ED2 and RIIO-ED3 price control periods; this reflects the investment required in the distribution network to enable the UK to reach the net zero targets by 2050. No assumptions have been made on other elements of totex post 2028 – these have been assumed to remain at 2028 levels. There would be movements in controllable opex to support changes in load related expenditure (such as network design and project management), but since post 2028 is so uncertain, no assumptions have been made.

Smart meter data and monitoring

4.37. Transitioning from a network originally designed to deliver passive operation, into one in which demand and generation is balanced locally by a mixture of enhanced sensing with active technical and commercial mechanisms. It will require significant change in our current role, but will facilitate a smarter energy system which can flexibly meet the needs of our users. The essential building blocks to achieve this are outlined in figure SA-06a.18.

4.38. We have developed functionality in all these areas and will continue to expand capability in these areas during RIIO-ED2. This will involve increasing data gathering from the network, enhancing established processes, developing new systems and sharing more data than ever before.

Enhanced network visibility and monitoring	Understanding how the network is performing is key to its efficient utilisation, so data from sensors and measurement devices is required at more places. Existing maximum demand sensors will be augmented to provide more detailed and frequent data about load and power flow direction. At low voltage, 15,500 of the highest priority substations, based on likely installed capacities, will have monitors installed. At high voltage, in order to facilitate the connection and active management of renewable power generators and energy storage installations, WPD will ensure that it has 100% visibility of the power flows on its network at all 1,800 of its primary substations.
utilising… **smart meter data**	Data will be further augmented with smart meter data to provide network information where monitoring is not available or required. We will utilise smart meters to: • Enhance and refine our network planning models (particularly on our low voltage networks). • Improve power cut response services. • Prevent faults by analysing smart meter data to proactively identify potential network issues.
to enable… **smarter more flexible networks**	We will oversee a network wide deployment of flexibility, avoiding £94 million of conventional reinforcement by maximising the utilisation of the existing grid. We will offer a suite of flexibility products, funding customers to provide import and export capping at key times of network constraint as an alternative to conventional solutions. We will only reinforce the networks when these solutions cannot deliver what is required.

Figure SA-06a.18 Outline of how WPD will use enhanced monitoring and smart meter data to inform forecasting throughout RIIO-ED2

5. Network impact assessment

5.1. After the expected customer behaviour assumptions are applied to the DFES volume projections, a data set of the expected loads from demand and generation on the WPD network is generated. This data is then mapped to a network model in power system analysis software to undertake detailed network analysis.

5.2. Traditionally, network studies were carried out using 'edge case' modelling where only the network condition that is deemed most onerous is analysed. With the recent growth in the connection of distributed generation, it has become more difficult to predict when the most onerous network conditions will occur and a more broad approach is now required.

5.3. WPD's Shaping Subtransmission reports published for each of our four licence areas outline our current methodology for identifying constraints on the network at the EHV level. This is done by analysing network behaviour throughout the day for:

- **Winter Peak Demand**, with minimum coincident generation – an assessment of the network's capability to meet peak demand conditions;
- **Summer Peak Demand** and **Intermediate Warm Peak Demand**, with minimum coincident generation – an assessment of the network's capability to meet maintenance period demand conditions;
- **Summer Peak Generation**, with minimum coincident demand – an assessment of the network's capability to handle generation output.

5.4. As WPD's network becomes more variable due to changing consumer behaviour, there will be greater emphasis on our role as a Distribution System Operator (DSO) which will require more analysis of this type to manage the network in real time.

5.5. The network is assessed for each of the four baseline DFES scenarios, with constraints that are expected to arise under each scenario identified. By performing analysis over all four growth scenarios, the range of uncertainty can be evaluated; constraints flagged under all four growth scenarios are deemed more likely than those that only occur under the higher growth scenarios.

5.6. To identify constraints at the Low Voltage (LV) and High Voltage (HV) network level, the forecasted volumes produced from the DFES process are loaded into a network modelling tool; the Network Investment Forecasting Tool (NIFT). This tool was specifically developed for WPD by EATL to identify LV and HV network reinforcement requirements. NIFT incorporates a model of WPD's LV feeders and HV transformers using WPD asset and geographic data, and maps the forecast localised demand and DER growth from DFES scenarios onto these simulated networks to identify where and when additional capacity will be required.

5.7. A number of parameters are considered during network analysis to determine if intervention is required. The thresholds for three of the main load related parameters to trigger intervention are shown in figure SA-06a.19 for each voltage level.

Voltage Level	Thermal	Fault Current[20]	Voltage
Low Voltage	100% of rating (distribution cyclic rating of the asset in the season of the constraint).	98% of rating	+10% to -6% of declared voltage at the declared frequency
6.6/11kV	100% of rating (distribution cyclic rating of the asset in the season of the constraint).	98% of rating	±6% of declared voltage at the declared frequency
33/66kV	100% of rating (distribution cyclic rating of the asset in the season of the constraint).	98% of rating	±6% of declared voltage at the declared frequency
132kV	100% of rating (distribution cyclic rating of the asset in the season of the constraint).	98% of rating	±10% of declared voltage at the declared frequency

Figure SA-06a.19 The thresholds for thermal, fault current and voltage constraints that trigger intervention at each voltage level

5.8. More information regarding the limits within which WPD operates its network can be found in the following documents published by WPD:

- Policy Document: SD4/9 (Relating to 11kV and 6.6kV Network Design).
- Policy Document: SD3/9 (Relating to 66kV and 33kV Network Design).
- Policy Document: SD2/8 (Relating to 132kV Network Design).

5.9. For the network, to assess the current and future available capacity and to identify constraints that require intervention during RIIO-ED2, the Best View growth data was compared against the firm capacities published in table 3 of the Long Term Development Statement (LTDS). The growth rates were at a primary level, so to produce suitable projections at a Bulk Supply Point (BSP) level the average growth rates of the primaries downstream from each BSP were applied to the max demands in 2019/20 from the LTDS. This approach helps us to account for diversity and should produce more accurate projections than simply summating the primary demand sets. For complex constraints involving multiple substations identified from the Shaping Subtransmission reports, the demands were summated, with diversity accounted for on a case-by-case basis.

5.10. Historically, WPD undertakes steady state analysis to establish a view of the behaviours of the network in the event of a fault. Going forward into RIIO-ED2, it will be increasingly important to study the stability of the system as the network becomes more active and the amount of distributed generation increases. This proposed stability analysis is described in EJP103.

5.11. At each stage of the load related investment process a number of assumptions are made which may materially affect the outcome. These assumptions are listed on the next page for the different voltage levels. More details on the modelling assumptions used for EHV analysis can be found in the DFES: Customer Behaviour Profiles and Assumptions Report published by WPD.

[20] Once calculations indicate switchgear is above 95% of its rating it should be considered overstressed, unless detailed studies can show otherwise to a value no greater than 98% at the discretion of the Primary System Design Team Manager as detailed in ST: SD7F/2 (Determination of Short Circuit Duty for Switchgear on the WPD Distribution System).

LV and HV impact

5.12. The key drivers expected to impact the low voltage and high voltage networks are the increased penetration of LCTs projected to connect at a household level. The DFES projections are disaggregated to a primary substation level. The Network Investment Forecasting Tool (NIFT) includes assumptions to further disaggregate the LCTs to each distribution substation and low voltage feeder level.

5.13. In the absence of measured data from network monitoring on the LV and HV networks, a profile class-based allocation method is used to forecast expected network loading. An extract from WPD systems is used to define the baseline customer and LCT numbers per distribution substation and LV feeder, onto which the DFES projections are layered. As part of the customer numbers, the number of LCTs and customer archetypes are included. Expected demand profiles for each customer archetype are applied to the customer numbers (accounting for diversity of multiple customers) to estimate network loading.

5.14. The extent of available capacity available on the low voltage and high voltage networks is provided as part of the Business Plan Data Table CV2 (Secondary Reinforcement). Ground mounted and pole mounted transformers are grouped into utilisation bands in the baseline year and also throughout the RIIO-ED2 period. Figure SA-06a.20 shows the number of transformers in each of the utilisation bands across the RIIO-ED2 period, where no network interventions are undertaken to address areas of high utilisation. Figure SA-06a.21 shows the number of transformers in each of the utilisation bands across the RIIO-ED2 period including network interventions projected to address areas of high utilisation.

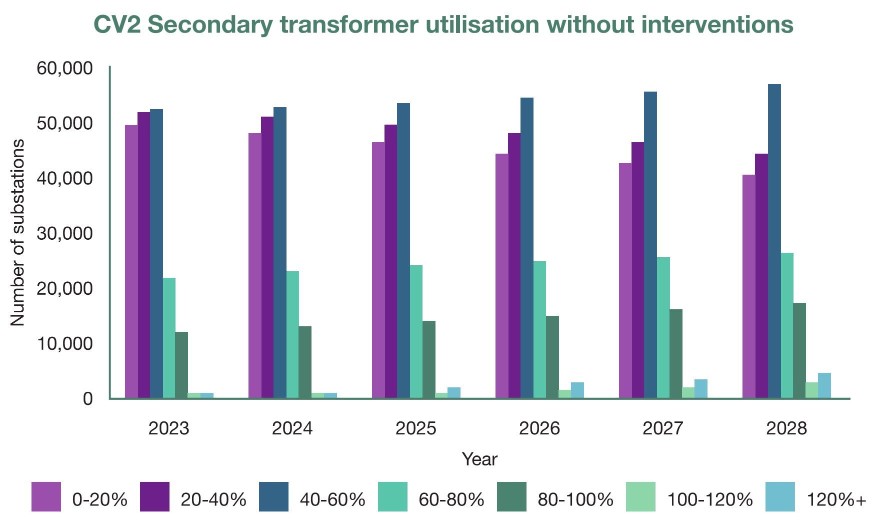

Figure SA-06a.20 Graph of the projected utilisation of secondary transformers across the WPD network across the RIIO-ED2 period, with no network interventions modelled

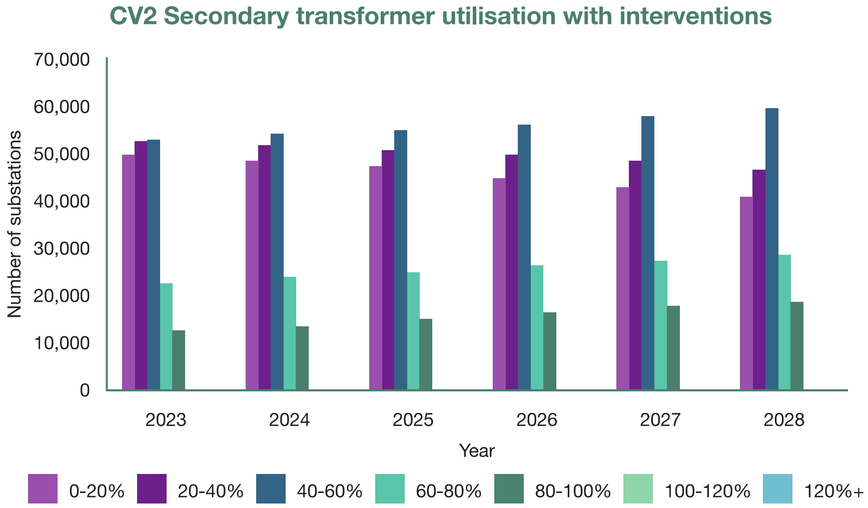

Figure SA-06a.21 Graph of the projected utilisation of secondary substations across the WPD network across the RIIO-ED2 period, with network interventions modelled

EHV impact

5.15. A yearly load survey is undertaken to determine the true demand at each primary, BSP and Grid Supply Point (GSP) substation. This load survey unmasks generation and flexibility to give the true underlying demand at a substation. This observed data is used for the starting load assumptions relevant to the voltage level and purpose of the network analysis at the EHV level.

5.16. It is not sufficient to look only at an aggregated demand or load when undertaking longer term strategic planning. There is a need to understand the constituent demand and generation that make up an aggregated load profile, as this enables modelling of changing customer behaviour over time. This lower level volume driven methodology ensures greater accuracy when determining projected growth and is not just based on historic trends.

5.17. As noted in the forecasting section of this annexe and the DFES: Customer Behaviour Assumptions Report, the customer behaviour assumptions account for how WPD expects customer electricity usage to change over time. At the EHV level the key drivers for load growth on our networks encompass the aggregate behaviour of the increased penetration of LCTs, accounting for the diversity of how large groups of customers behave in aggregate. Larger customers connecting directly to the EHV networks (such as distributed generation) also act as a key driver for the EHV network impact assessment.

5.18. To enable accurate analysis on the distribution network, a representative Transmission model is necessary. This Transmission representation is an equivalent of the full Transmission network and, when incorporated into the WPD power system model, approximates the network behaviour. This data is provided by National Grid as part of the Week 42 data exchange. The size of the equivalent model varies for each licence area, depending on the level of GSP parallel running and interconnection.

5.19. Where there is an interface with other DNOs, the interaction between the networks is assessed using power system software. Generally, the network data can be taken from the other DNOs' LTDS publication, but bespoke models are also exchanged where LTDS data is insufficient to ensure accurate analysis can be undertaken. Collaborative analysis is undertaken and cross DNO meetings are used as an effective forum.

5.20. A weather correction factor produced by TESLA on behalf of WPD accounts for key weather variables. It is provided at hourly granularity and is applied to the demand prior to finding the underlying peak demand. Weather correcting demand allows for extreme weather conditions to be offset, enabling more accurate comparisons with historic data to be carried out.

5.21. The extent of available capacity available on the EHV networks is provided as part of the Load Index tables submitted in the Business Plan Data Tables. The maximum demand for each substation (including groups thereof) is assessed against the firm capacity calculated for the season of most onerous demand. Substations as part of the EHV networks are grouped into utilisation bands in the baseline year and also throughout the RIIO-ED2 period. Figure SA-06a.22 shows the number of substations in each of the utilisation bands at the start and end of the RIIO-ED2 period and without network interventions undertaken to address areas of high utilisation.

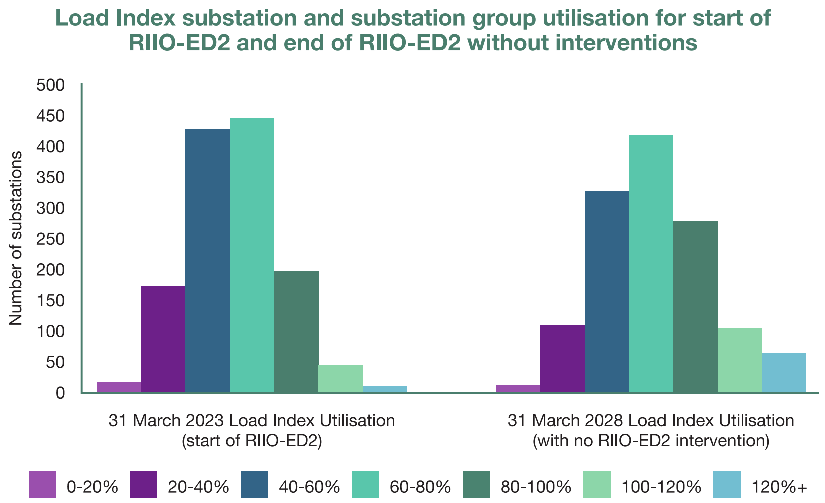

Figure SA-06a.22 Graph of the projected utilisation of EHV substations across the WPD network across the RIIO-ED2 period, with no network interventions modelled

5.22. Figure SA-06a.22 clearly shows the forecast increase in utilisation under WPD's Best View from the start of ED2 to the end of ED2 if no interventions were to be undertaken to alleviate future network constraints. Without any interventions, there would be a significant increase in LI4/LI5 rankings and loading risk points across all licence areas. Through interventions, we are able to keep our loading risk points at the end of ED2 broadly the same as the start of ED2. Interventions utilised to manage network risk are outlined below; however, it is worth noting that not all of these interventions are requisite aspects of the firm capacity forecasts outlined in the Load Index tables.

- General EHV network reinforcements
- Flexibility
- Connection driven reinforcement
- 11kV reinforcement that adds capacity to the EHV network

5.23. Figure SA-06a.23 outlines how the unutilised demand from customers with Connection Agreements are accounted for in the Load Index tables. The Load index maximum demand is calculated from the sum of the observed demand, the Weather Correction (WC) adjustment and the output of Distributed Generation (DG) at the time of observed maximum demand. In addition to the Load Index maximum demand, additional demand from customers with Agreed Supply Capacity (ASC) from Connection Agreements not utilised at the time of observed maximum demand can also be included. The inclusion of the unutilised ASCs can alter the Load Index of a particular substation. For the RIIO-ED2 Business Plan Data Tables, we have provided both the Load Index maximum demand with and without the contribution of customers with unutilised demand from Connection Agreements. This aims to highlight the level of risk which WPD accounts for in network planning to ensure a coordinated and efficient network is designed for customers.

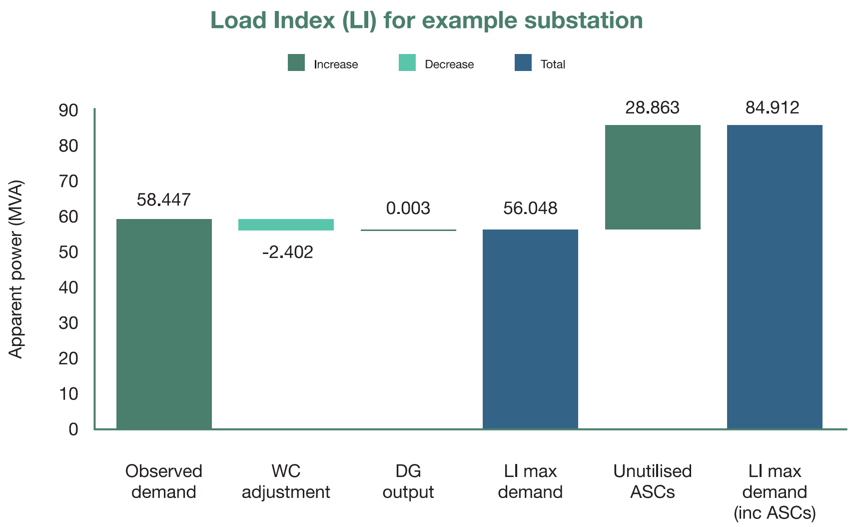

Figure SA-06a.23 Waterfall graph of an example substation to outline how the unutilised Agreed Supply Capacity from customers with Connection Agreements alter the Load Index

6. Optioneering

6.1. Once the parts of the distribution network that are expected to become constrained in the near future have been identified, the next step is to identify the optimal solution to deal with each constraint. WPD’s optioneering process considers the costs, technical feasibility, deliverability and impact on the wider network of each possible solution to ensure the chosen investment delivers value for money for stakeholders and customers without compromising the security and sustainability of the network.

6.2. To properly assess the impact of a possible solution on the network, studies are run for each scenario in a Switch Level Analyser (SLA). This analysis helps engineers identify situations where multiple constraints can be solved with one solution, or where certain solutions exacerbate other load and non-load related issues. By studying these effects, WPD ensures the chosen solutions synergise and the overall cost is minimised without sacrificing network security well into the future, and the deliverability of projects in subsequent price control periods is not compromised (which may necessitate less optimal solutions in the short term in some cases).

6.3. Detailed information for the WPD process for low voltage and high voltage optioneering is outlined in EJP112 (Secondary Reinforcement Programme). The NIFT tool considers three different options for the network impact assessment of low voltage and high voltage networks which are based around the following types of flexibility.

- **Passive flexibility** is the assumption that not all of our customers use the network in the same way at the same time. For example, customers that have LCTs such as EVs or heat pumps connected to our network won’t all use their equipment at times of peak. There will be some demand led customers that are tariff responsive and thus will use the network at shoulder periods. These assumptions around Passive Flexibility flow into our LV and HV reinforcement model and can contribute to the deferring of conventional LV and HV reinforcement.
- **Active flexibility** is the ability to use DSO led active flexibility to turn down demand or turn up generation of electricity in real-time. This would require our customers to use smart technologies to enable their existing devices to flex regarding electricity. Smart technologies such as smart meters can facilitate active flexibility.

6.4. Our optioneering approach used to identify and evaluate schemes on the low voltage and high voltage networks is built on the knowledge gained from various areas of the business while operating as a DNO for over 20 years. Three different combinations of how active and passive flexibility is used in conjunction with unrestricted customer behaviour profiles are modelled.

- Secondary Network Reinforcement without Passive Flexibility.
- Secondary Network Reinforcement with Passive Flexibility.
- Secondary Network Reinforcement with Active and Passive Flexibility.

6.5. As part of WPD’s extra high voltage optioneering process, the Distribution Network Options Assessment (DNOA) is a document published twice a year providing transparency in the investment decision making process. The DNOA framework set out by WPD will solidify robust and transparent processes to ensure independence of decision.

6.6. WPD’s DNOA uses the Common Evaluation Methodology (CEM) developed under the Open Networks project to compare options and identify low regret pathways. Conventional reinforcement is always considered as a base case, with flexibility considered alongside. In some cases, alternative conventional solutions are also considered, or additionally other innovation solutions that might be available (voltage management/voltage compensation etc.).

6.7. The decisions made are based on a number of factors and are evidenced through the CEM output. Figure SA-06a.24 shows the decision tree used to determine how best to manage a constraint that has been identified. A more in depth account of WPD's methodology can be found in our DNOA report.

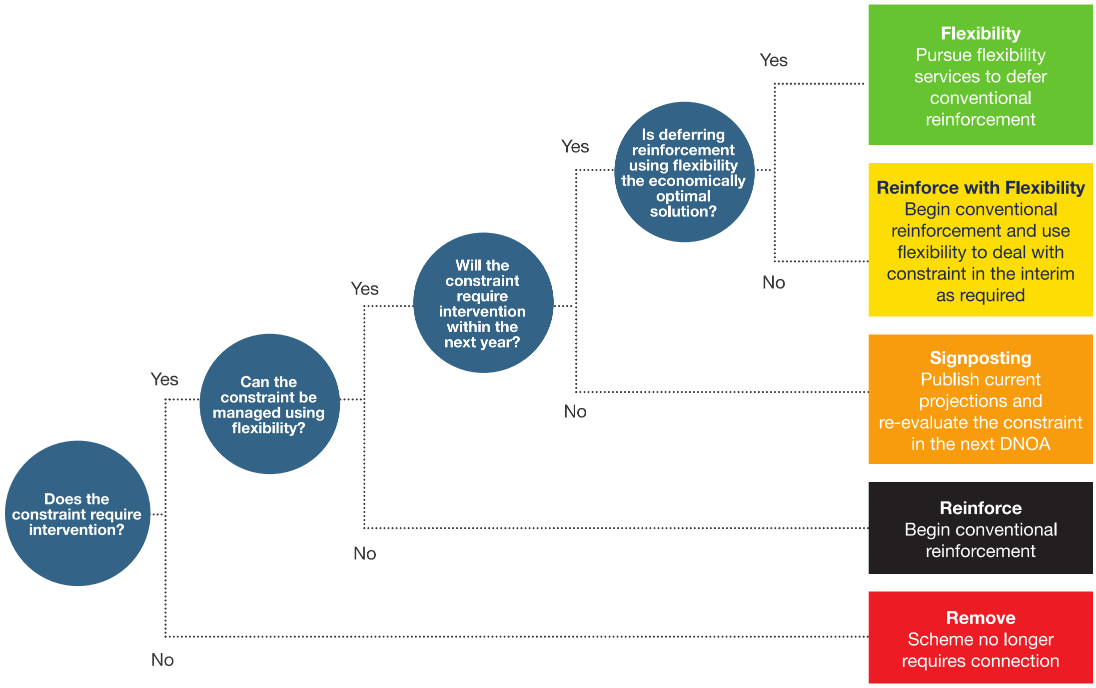

Figure SA-06a.24 A decision tree representing WPD's process in determining the optimal solution for dealing with a given constraint

Reinforcement

6.8. Conventional reinforcement solutions are derived to establish a reference against which alternative solutions can be compared. These solutions usually involve alleviating constraints on the network by uprating existing assets or installing new assets. Building new circuits/substations and uprating existing circuits/substations increases the capacity of the network, allowing WPD to continue to maintain security of supply and network resilience as demand increases.

6.9. Conventional reinforcement schemes are usually associated with large upfront costs, and take a significant amount of time to plan and carry out. However, reinforcing the network is a reliable and long term solution to a constraint. Additionally, uprating assets improves efficiency and lowers losses on the network.

6.10. There may be numerous viable reinforcement options to deal with a given network constraint, each of which are considered with regards to cost, deliverability and wider effect on the network. The availability of land and other such factors are also considered when assessing the viability of each reinforcement option.

Load management schemes

6.11. Load management schemes (LMS) involve managing network loading and voltages by either controlling demand and/or generation connected to the network, operating switchgear to change the topology of the network and/or controlling the settings of tap-change controllers, reactive compensation equipment and flexible power links. This can be used to shift load away from certain assets to alleviate constraints. In areas where multiple complex constraints are affecting a number of customers over a long period of time, Active Network Management (ANM) can also be implemented. The feasibility of LMS and ANM depends on the configuration of the network around the constraint, such as how heavily loaded nearby assets already are. Where possible, this solution is a relatively cheap and effective solution to some constraints.

Asset stranding risks

6.12. We have taken a deliberate approach to ensure any reinforcement proposals are optimised for 2050. Whenever possible and economic to do so, we have ensured that the adopted solution adds sufficient network capacity headroom that ensures adequate capacity for all scenarios until at least 2050.

6.13. However, where this is not possible, we have considered and confirmed that any further necessary reinforcement would not in any case require removal or make any of the proposed new added assets redundant. This embeds a “touch once to 2050” approach in our network development processes.

6.14. Flexibility is also used to defer conventional reinforcement and this can be used to provide more time to assess the certainty of requirements and the scale of new capacity required. We are working with industry within Open Networks to better understand how to value this additional optionality and will employ these improvements within our DNOA processes for recommending network investment.

Flexibility

6.15. During RIIO-ED1, we established flexibility markets that provide a means of addressing network constraints to defer conventional reinforcement. These make use of new technology and the ability for some network users to provide flexibility in their own consumption either by increasing, reducing or shifting their net import or export during peak loading periods. A number of flexibility products are offered to eligible providers in constraint management zones (CMZs) within WPD’s licence areas. This procurement is carried out in cycles on a six-monthly basis. Flexibility is most suited for constraints where assets are only slightly overloaded.

6.16. We anticipate that the use of flexibility will increase during RIIO-ED2 although it is not expected that the market will be able to provide services to match all constraints. Our 'flexibility first’ approach outlined in our Business Plan commitment 35 means that, for all constraints, we consider whether flexibility is a viable option to address network issues and defer reinforcement.

6.17. To determine whether the costs of flexibility procurement are less than the benefit of deferring expenditure associated with reinforcement, cost-benefit analysis is carried out for each scheme using the CEM Cost Benefit Analysis (CBA) tool, as part of the DNOA process. Flexibility is not suitable for some types of constraint, such as fault level issues.

6.18. We also cannot guarantee that enough flexibility providers will be available to deal with a given constraint but, by signposting and testing the market in advance, we can determine if this is the case and fall back on other solutions if necessary without jeopardising our commitment to maintain a secure and sustainable network. In RIIO-ED2 we will continue to refine our processes and identify more ways of encouraging third parties to consider providing flexibility services.

Innovative solutions

6.19. During RIIO-ED2, smart grid solutions such as System Voltage Optimisation (SVO) will be applied more widely. For these smart systems to operate effectively, we need more detailed information about the network loading and status. WPD is dedicated to searching for innovative solutions to load related constraints on the distribution network, and will continue to do so throughout RIIO-ED2.

6.20. For each innovation project, we will undertake cost-benefit analysis and a carbon assessment. We will ensure roll out into business practice to improve efficiency and effectiveness of assets, operations and customer service.

6.21. To operate the network in a cost-effective way and avoid unnecessary expenditure from asset stranding, we have identified a number of enhanced network monitoring requirements. A number of enhanced network monitoring projects are planned for RIIO-ED2 to fulfil these requirements:

- **Distributed energy resource SCADA Monitors:** This project will continue a programme of retro-fitting telemetry to customer points of connection where significant distributed generation or other flexible DER are located.
- **EHV monitoring for Smart systems:** This project will proactively fit additional sensing and monitoring to sections of the network prioritised for expansion of smart solutions.
- **Power quality monitoring:** This project will install monitoring for power quality on a continuous basis.
- **LV network monitoring:** Monitoring at LV will provide greater visibility of the loads, allowing proactive measures to be taken in real-time and providing a more accurate view of reinforcement requirements, deferring the requirement at some sites and enable improvements to modelling assumptions to be made.
- **Internet protocol substation:** This project will test this IP approach to protection and SCADA to establish the working practices and policies for wider deployment.

6.22. More information regarding WPD’s approach to monitoring can be found in our Sensors and Measurement strategy. Significant upgrades to our measurement capability are planned by adding more sensors at all voltage levels within the distribution network. This enhanced network monitoring will allow us to stay informed ahead of change during the network design process.

7. Load related investment plan

7.1. Load related expenditure within RIIO-ED2 will be characterised by the impact of LCTs. Demand consuming technologies such as electric vehicles and heat pumps will contribute to increasing demand constraints on the network if their consumption coincides with existing peaks.

7.2. These technologies will predominately be connecting to the low voltage networks so, due to the traditional centralised model of generation to supply local demand, the impact may be felt at all voltage levels up to and including transmission.

7.3. Electricity-generating technologies will potentially offset some of the impacts of increased demand, if they are co-located and coincident in time.

7.4. While significant progress has been made in developing forecasting on the distribution network, there is still a greater amount of uncertainty compared to RIIO-ED1. Figures SA-06a.25 and SA-06a.26 show WPD's DFES peak demand forecast and energy distributed forecast out to 2030.

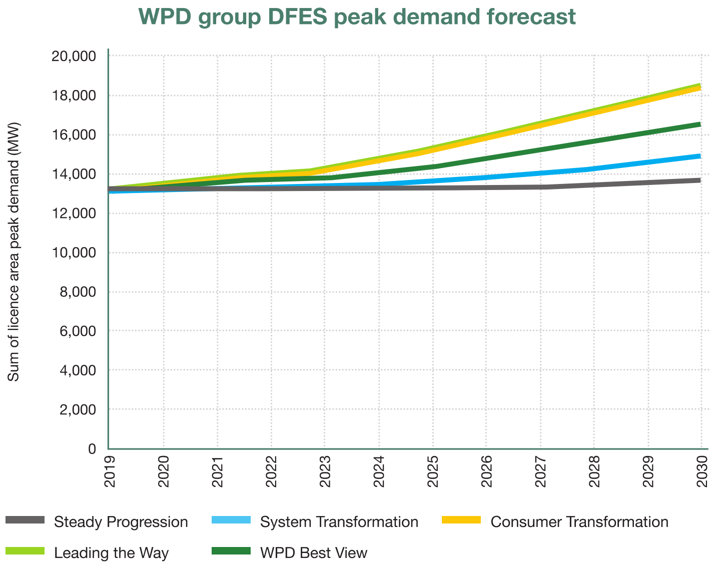

Figure SA-06a.25 Graph showing WPD Group peak demand in MW out to 2030 across the four DFES scenarios and WPD Best View

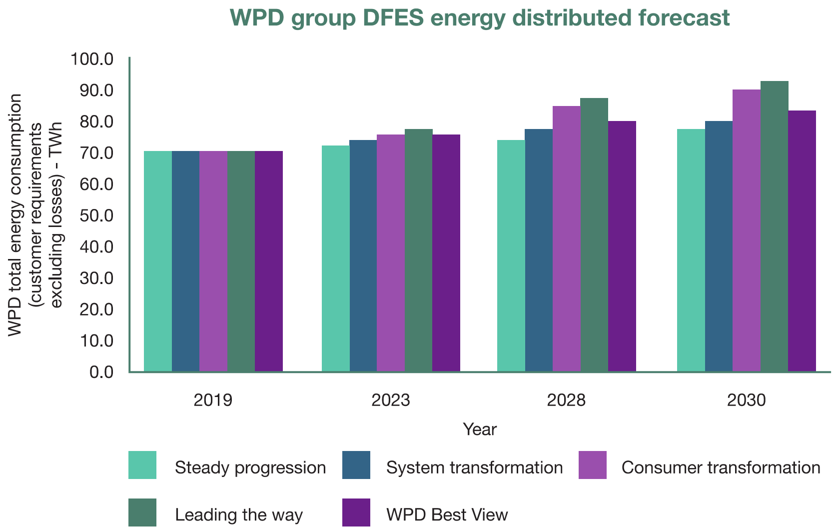

Figure SA-06a.26 Graph showing WPD Group forecast energy consumption in TWh out to 2030 across the four DFES scenarios and WPD Best View

7.5. Within RIIO-ED2, there are a number of elements that contribute to the uncertainty of the impacts:

- Volumes of LCTs
- Electrical profiles of the LCTs and their contribution to peak capacity requirements
- Energy efficiency
- Location of LCTs
- Voltage level of connection
- Impacts of pricing-led DSR
- Availability and cost effectiveness of DSO led flexibility

7.6. In RIIO-ED1, expected volumes and costs of load related reinforcement were justified ahead of the price control period, with a symmetric 20% materiality threshold applied to the total expenditure, outside of which a load related reopener could be triggered.

7.7. Efficient delivery of the expenditure is incentivised by the TIM (Totex Incentive Mechanism), which allows for a DNO-specific sharing factor to be applied to any over or under expenditure, balancing risk and reward between DNOs and customers.

7.8. In RIIO-ED2, the expected range of possible end of price control outcomes is expected to be a much greater compared to RIIO-ED1; expenditure required under the WPD Best View scenario may have to be increased by 102% to manage the loads projected in 'Leading the Way' by 2028 or reduced by 45% if the 'System Transformation scenario is followed.

7.9. To enable the RIIO-ED2 price control to deliver sufficient, timely capacity to support decarbonisation, while protecting customers from unnecessary or inefficient investment and also maintaining a simple and pragmatic regulatory overhead, new mechanisms must be designed. WPD expects uncertainty mechanisms to play a larger part in load related expenditure than during RIIO-ED1 and the potential scale requires new agile mechanisms to be proposed.

Sizing the load related expenditure

7.10. DNOs will need to invest upfront to reach the delivery capacity required under high certainty, but the actual investment required will be driven by national and local government policy, combined with activity in the consumer market. These factors are likely to change during the price control period, so load related expenditure needs to be agile enough to respond to these changes.

7.11. There will be more certainty of the investment in some areas where it is supported by historic growth, national targets and local area enablers. Using the Distribution Future Energy Scenarios framework (DFES), WPD has identified the volumes and locations of constraints in each scenario and the likely low regret investment required to accommodate the forecast growth.

7.12. Gross network investment triggered under any of the three net zero compliant scenarios from the DFES within the WPD group area totals £2,269 million, with a split of £904 million resulting from reinforcement of the primary network and £1,365 million across the secondary network. This has informed our high case scenario presented in the Load Related Expenditure Business Plan Data Table.

7.13. Through stakeholder engagement, forecasting and scenario modelling, WPD's Best View has been created, which identifies the most credible and likely growth which investment is needed to manage. Modelling based on WPD's Best View reduces the gross expected investment down to £1,020 million, split £434 million and £586 million between primary and secondary expenditure respectively[21]. This has informed our baseline Totex submission.

Dealing with uncertainty

7.14. Identification of the investment triggered under the net zero compliant scenarios (System Transformation, Consumer Transformation and Leading the Way) has been completed through our scenario modelling process. This is then compared against the investment triggered under WPD's Best View growth scenario, which is being presented within our Business Plan as the base case for our ex-ante load related expenditure.

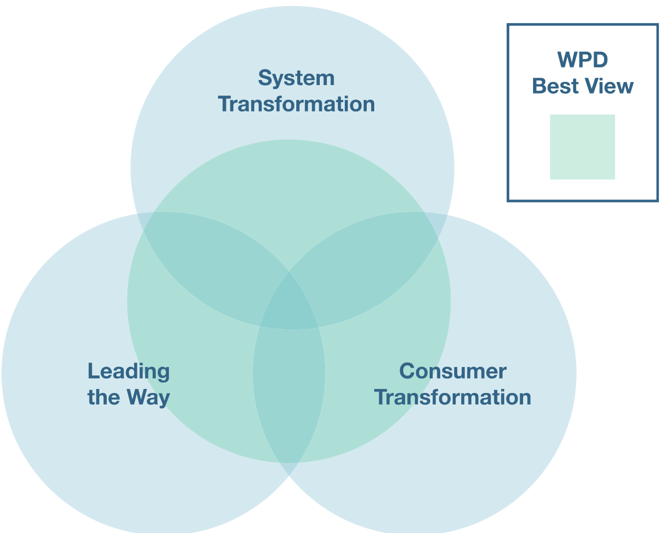

Figure SA-06a.27 Graphic showing the relationship between the three net zero compliant DFES scenarios and WPD's Best View

7.15. Our Best View is not a simple application of the lowest growth scenario which is still net zero compliant, but has been built by identifying the investment required to support all three net zero

[21] These are gross (before customer contributions) investment values which include connections inside the price control and primary and secondary general reinforcement. The values in Supplementary Annex 6 are presented after customer contributions and are analysed between connections and general reinforcement.

compliant scenarios. It is also supported by stakeholder engagement and WPD due diligence in the maturity of the LAEPs. It is composed by applying different scenarios across local authority areas, leading to a locally-led, and bottom up view of the required investment most likely.

7.16. We recognise there will be great variation in the speed and pathways taken to decarbonise local areas. WPD's Best View is a blended scenario which applies one of the four DFES scenarios at a local authority level, and still delivers an outcome that is within the range of the three net zero compliant scenarios. This enables investment to be triggered under more aggressive decarbonisation scenarios in areas well supported by mature LAEPs, historically higher LCT uptakes and tangible local initiatives driving decarbonisation. It allows areas with less clear decarbonisation pathways to be assigned to Steady Progression, protecting bill payers from potentially suboptimal investment compared to assigning a single licence area scenario forecast.

7.17. We have used the DFES volumes and electrical behaviours to inform future growth rates across the local areas in its region. Using this information coupled with scenario planning techniques, potential constraints can be identified and reinforcement options can be taken forward. Many investments required in the price control will be the same for Best View as it would for any net zero scenario, as the capacity being delivered caters for any scenario. These are high certainty investments. Where different scenarios could result in a potential variation to the investment decision, the Best View is used with a higher probability as it represents the most credible DFES scenario based on stakeholder engagement in that location.

7.18. While the WPD Best View is based upon our assessment of the most credible outcome, the potential impacts of other growth scenarios have been assessed. Additional reinforcement works required above the WPD Best View are used to inform the sizing potential of investment required under any single DFES scenario. We have named this scenario 'Any single DFES scenario' and intend to deliver investment within this category through the use of uncertainty mechanisms. This scenario has informed our high case scenario presented in the Load Related Expenditure Business Plan Data Table.

7.19. Through the RIIO-ED2 period, we will be managing the uncertainty through an agile approach to forecasting, constraint identification and investment decision making. This will form an iterative cycle (see Figure SA-06a.28) where we maintain a continually updated view of most credible reinforcements and flexibility requirements through the price control.

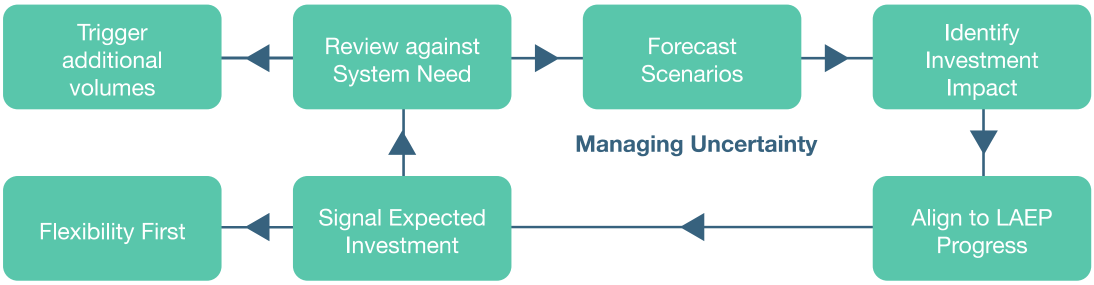

Figure SA-06a.28 Cycle of managing uncertainty through the price control

Delivering benefits through flexibility

7.20. Delivering flexibility successfully will require WPD to use its longer term forecasting capability to signpost information on constraints well ahead of when the investment decision is required. WPD has a mature approach to flexibility, with 709MW in contract already and well established processes and timescales for procuring additional flexibility.

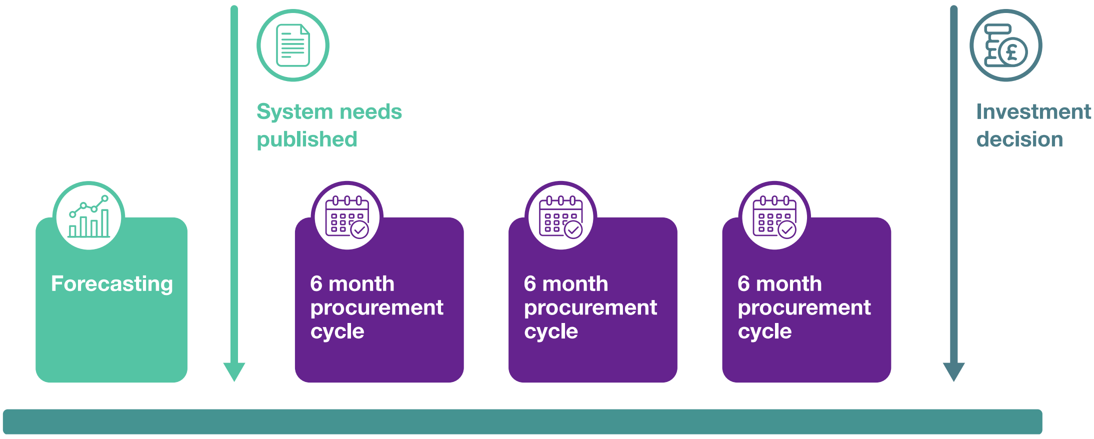

Figure SA-06a.29 Timetable for providing visibility of flexibility services

7.21. Within the ex-ante load related expenditure, where constraints can be mitigated by flexibility and the likely cost and availability is credible, we have factored the expected savings from non-network alternatives into its forecast expenditure as shown in figure SA-06a.29. This means our ex-ante allowance already assumes successful delivery of flexibility and we are immediately sharing the benefits of this with customers. Unlike RIIO-ED1, we are not requesting allowances to cover the more expensive conventional reinforcement upfront with a promise to return savings back to bill payers. Our approach in only requesting the flexibility funding directly delivers these savings immediately, with the DNO taking on the risk of non-delivery.

7.22. We have identified 58 potential Primary reinforcement schemes (of 192 on the initial reinforcement list, and including connections driven reinforcement) where we anticipate that flexibility will defer the traditional investment scheme beyond the RIIO-ED2 period.

7.23. The scaling up of Secondary network flexibility will see 12% of our HV/LV transformer programme able to be deferred. By 2028 WPD will be operating 518 LV constraint managed zones, resulting in £13 million of reinforcement being avoided.

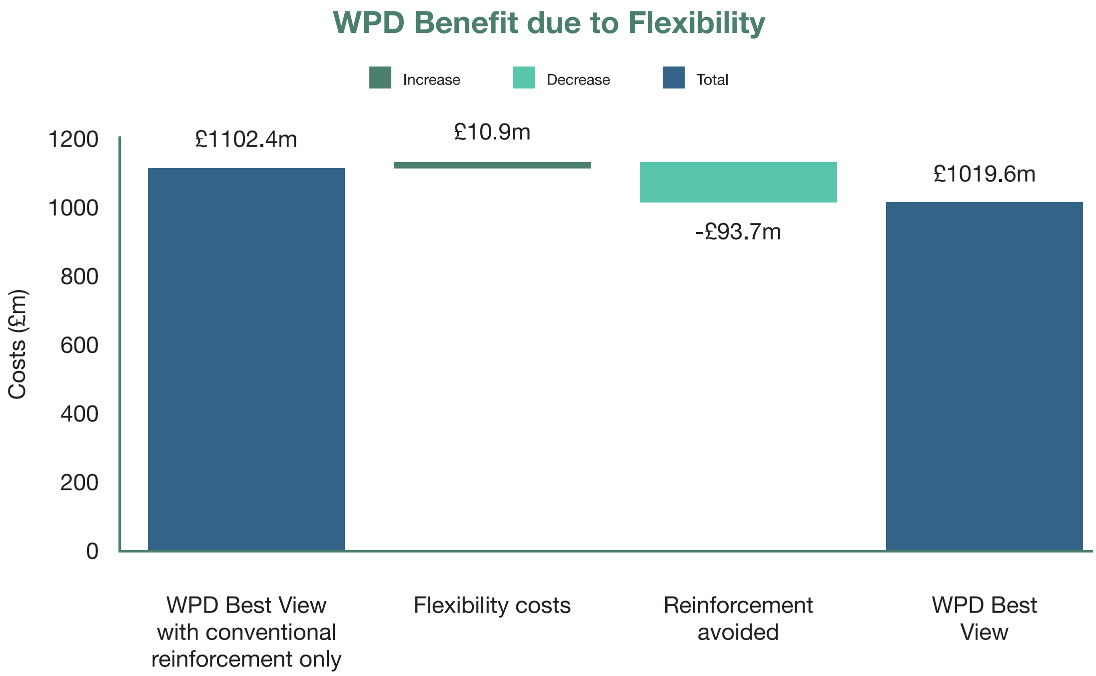

Figure SA6a.30 Waterfall graph showing costs and benefits due to flexibility across RIIO-ED2

7.24. Within RIIO-ED2, flexibility is expected to defer to future price control periods £94 million of load related expenditure otherwise anticipated within the Best View at a cost of £11 million. The effects flexibility procurement is expected to have on expenditure during RIIO-ED2 under our Best View are shown in figure SA-06a.30 above.

Use of uncertainty mechanisms

7.25. WPD is proposing a series of uncertainty mechanisms across three different investment categories to enable both increases and decreases in the levels of expenditure. Additional uncertain expenditure resulting from faster progression to net zero will be facilitated, resulting in our commitment to be able to deliver any DFES scenario outturn. Should decarbonisation have a lower impact on networks than anticipated in the price control, customers will be protected from underinvestment resulting from those lower requirements through reductions in allowances. The difference in investment required between WPD's Best View and the 'Any single DFES scenario' (our high case) will be delivered through uncertainty mechanisms as shown in figures SA-06a.31 and SA-06a.32 below.

Gross investment, £ million, 20/21 prices

	High Case	WPD's Best View	Low Case
Primary	904	434	324
Secondary	1365	586	460
Total	2269	1020	785

Figure SA-06a.31 Total potential investment across RIIO-ED2 relating to primary and secondary networks split

7.26. Flexibility markets will enable opportunities for more efficient delivery. The price control will need to allow for this where routes are economic and available, without committing DNOs to undeliverable outcomes or creating disincentives by reducing potential rewards. Uncertainty mechanisms must facilitate multiple pathways to mitigating constraints through conventional and non-network alternatives.

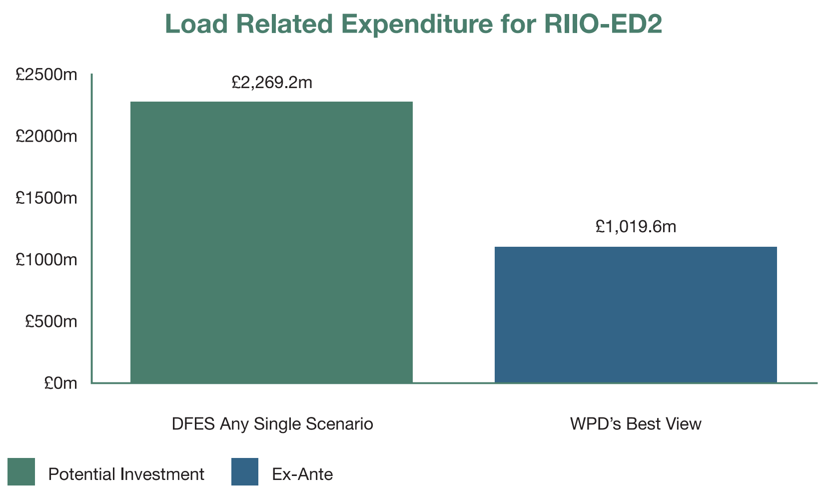

Figure SA-06a.32 Total investment across RIIO-ED2 showing potential expenditures

7.27. While the proposed ex-ante allowance being requested under the Best View represents investment identifiable now with a high certainty of being triggered during RIIO-ED2, there may be further changes to the required investment during the price control period. These potential differences are likely to be much greater than those observed in RIIO-ED1. The ability to deliver this change in expenditure will be taken forward through uncertainty mechanisms proposed by WPD. In order to balance risk, agility and complexity, WPD is proposing that simple volume drivers are applied to the load related expenditure which is discrete, uniform and measureable, such as secondary investment and service unlooping, to ensure that anticipated, but uncertain, activity during the price control can be funded.

Secondary load related expenditure uncertainty mechanism

7.28. On the secondary network, activity involved in providing additional capacity to customers will likely involve upgrading or installing new HV and LV circuits, as well as upgrading or adding new pole mounted or ground mounted distribution transformers. Some of this activity may also be deferred or avoided due to flexibility.

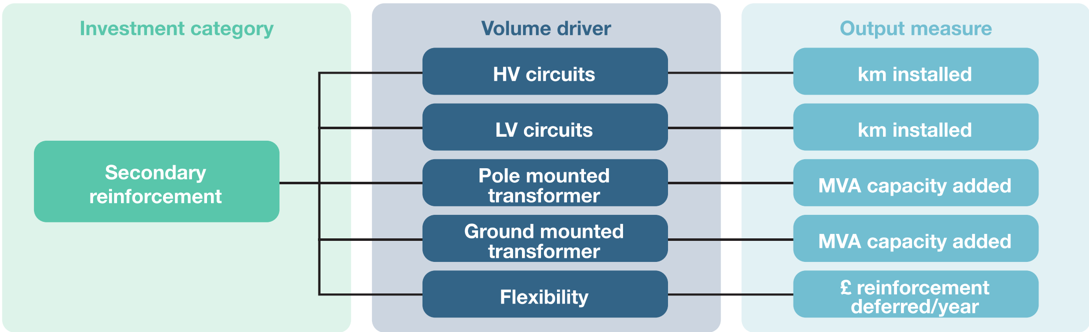

Figure SA-06a.33 Graphic relating output metrics to activity categories for secondary network investment

7.29. As this work has historically had the costs and volumes of activity reported at an aggregated licence area level, moving it to a symmetrical volume/capacity driver and unit cost model requires little adaption to existing regulatory processes.

7.30. For linear assets we are proposing a volume driver unit aligned to the length of asset installed (in kilometres), split between LV and HV circuits (see figure SA-06a.33). For transformer capacity, we are proposing a measure of capacity added (in MVA), split between overhead and underground networks due to the variation in costs. Flexibility will be reported against the volumes of conventional reinforcement deferred. Unit costs will be agreed ex-ante.

7.31. Where flexibility is forecast to be employed, only the flexibility costs, have been included in the ex-ante forecast and not the full conventional reinforcement costs, providing immediate savings for consumers. If flexibility is delivered as predicted, no further costs are required.

7.32. The proposed uncertainty mechanism will account for investment above or below our ex-ante Best View. We will provide annual volumes of activity profiled for our Best View across these categories. Where the volumes delivered differ from these profiles, an annually triggered uncertainty mechanism based on the ex-ante unit costs and volumes delivered will be applied to adjust any allowances in both directions.

7.33. If changes to the economic or viability of the forecast investment option result in a project due for delivery by conventional reinforcement being delivered by flexibility, or vice-versa, then flexibility allowance uncertainty mechanism will apply.

7.34. The outturn and forecast load index reporting tables in CV2 will ensure investment within the secondary network is undertaken according to system need, taking into account that monitoring and visibility on the secondary network will improve during the price control period. Our IT plans include investment in LV Monitoring and smart meter data. We forecast that this will defer over £59 million of secondary reinforcement investment, which is therefore excluded from this forecast.

Primary load related expenditure uncertainty mechanism

7.35. On the primary network, activity involved in providing additional capacity to users will require greater bespoke activity, differing across voltage levels and geographic locations. Projects may range between a few hundred thousand pounds through to >£25 million. Scheme numbers are also lower in volumes than for secondary network activity. Significant progress has been made in RIIO-ED1 to allow primary network investment to be deferred or avoided through flexibility.

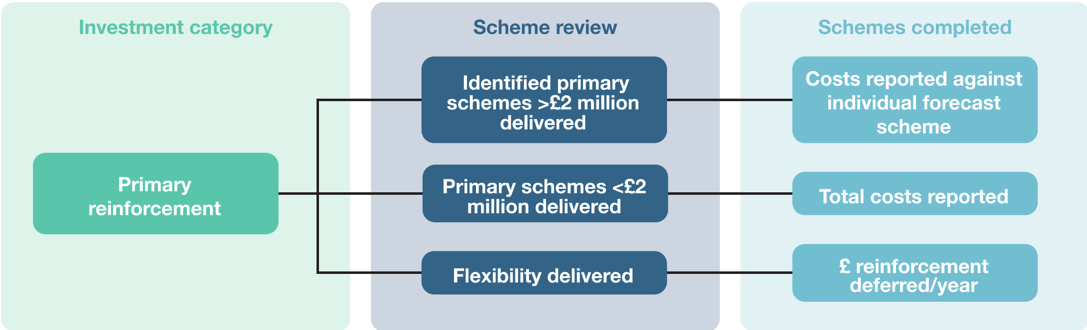

Figure SA-06a.34 Graphic relating output metrics to activity categories for primary network investment

7.36. Traditionally, investment has been well justified ahead of the price control and funded ex-ante, with a load related reopener triggered outside of a materiality limit. The scale of potential uncertainty within RIIO-ED2 means this approach is no longer valid across the whole portfolio of projects. The difference between WPD's Best View and Any single DFES scenario is over double, requiring a very large bandwidth to deliver all net zero scenarios, which is not practically delivered by continuing with RIIO-ED1 Load Related Mechanisms.

7.37. WPD has committed to provide Engineering Justification Papers (EJPs) for all load related expenditure above £1 million, demonstrating transparency of the required investment and ensuring there is robust justification. As we anticipate the volume and scale of primary reinforcement will be larger than in RIIO-ED1, we are proposing that the primary load related expenditure will also be enabled by two symmetrical uncertainty mechanisms (see figure SA-06a.34).

7.38. For projects delivered across the primary network under £2 million, the total investment will be aggregated together and profiled across the price control. This will be funded by an ex-ante allowance which will be subject to an RIIO-ED1-style load related reopener with a +/- 20% dead band and appropriate materiality threshold. Any deviation from the ex-ante allowance will be subject to the Totex Incentive Mechanism (TIM) sharing factor, sharing the risk and benefits between customers and DNO.

7.39. For primary network projects where the expected cost exceeds £2 million, the uncertainty mechanism will follow a 'PCD-lite' approach meaning schemes not delivered will be fully refunded. Here, actual project costs, as justified in the EJPs, will be set as the ex- ante allowance.

7.40. Where flexibility is forecast to be employed, only the flexibility costs will be included in the ex-ante allowance and not the full conventional reinforcement costs, providing immediate savings for consumers and a best view bill impact. If flexibility is delivered as predicted, no further costs are required. As these costs will be aggregated in the sub £2 million project allowance, cost variances will be subject to the TIM sharing factor, further sharing the risk and benefits between customers and DNO.

7.41. The proposed uncertainty mechanism will account for investment above or below our ex-ante Best View. Where schemes in excess of £2 million are not delivered in the price control, these will be fully refunded. Schemes under £2 million will be subject to greater churn, but customers will be protected from underspend through application of the TIM sharing factor. Where growth exceeds the allowances, new £2 million+ projects will have EJPs created and submitted as part of the regular Network Development Plan (NDP) publication under licence condition 25B for the regulator to approve, or instruct a direction for further work on the NDP until it can be approved.

7.42. Figure SA-06a.35 shows how the WPD Best View is divided to schemes which will be aggregated together and those above £2 million which will require EJPs to be submitted.

	Number of schemes under £2m	Number of schemes over £2m
East Midlands	4	21
South Wales	3	13
South West	6	12
West Midlands	5	12

Figure SA-06a.35 WPD's Best View split between number of schemes under and above £2 million

7.43. If changes to the economic or viability of the forecast investment option result in a project due for delivery by conventional reinforcement being delivered by flexibility, or vice-versa, then the flexibility allowance uncertainty mechanism will apply.

7.44. At the end of the price control, should no re-openers be triggered, all primary reinforcement activity costs will be aggregated together and reported against the ex-ante allowance. The ex-ante allowance will be modified downwards for any schemes over £2 million which have not been delivered and it will be modified upwards for any additional schemes reported through the NDP publication which have been approved by the regulator. Flexibility usage and benefits reported in the E6 table will be used to inform flexibility allowances. All allowances will be summated and TIM will be applied on the total variances on costs against the RIIO-ED2 allowance

7.45. The outturn and forecast load index reporting tables will ensure investment within the primary network is undertaken in line with system need.

Flexibility Allowance uncertainty mechanism

7.46. During RIIO-ED1, flexibility has been used to defer reinforcement. Benefits of this have been shared between customers and networks using the TIM, but this runs the risk of double or triple funding if the conventional reinforcement is taken forward in a future price control. The existing treatment of flexibility deferral unlocking the full funding of the conventional reinforcement, has greatly incentivised the uptake of flexibility, but is not suitable given the maturity of the solution now.

7.47. If deploying flexibility only where economic for reinforcement deferral, the flexibility service costs should be less than the benefit of not borrowing for the conventional reinforcement, for the time period of deferral. This results in the flexibility costs being order of magnitudes lower than the conventional reinforcement costs. This poses significant risk on the networks should a scheme forecast to be delivered by flexibility become uneconomic or unviable; a single flexibility scheme moving to being delivered conventionally would materially impact allowances.

7.48. A flexibility allowance uncertainty mechanism could protect customers from over funding where the application of flexibility is more favourable and equally protect networks where the application of flexibility is adverse.

7.49. The flexibility allowance is not a volume driver itself, as the volumes of activity are managed through the agreed ex-ante allowances and the proposed primary and secondary uncertainty mechanisms. Instead, it is an uncertainty mechanism to switch between a flexibility and reinforcement pathway allowance, ensuring DNOs undertaking conventional reinforcement in the case of flexibility not being available is not penalised and that where flexibility provides greater opportunities for deferring conventional reinforcement, customers are protected against double funding across price controls.

7.50. The proposed uncertainty mechanism will account for changes in the use of flexibility; where existing Primary or Secondary allowances become viable for flexibility in the price control. As the conventional reinforcement will not be being delivered, this will be fully refunded. The conventional reinforcement costs from the EJP or agreed ex-ante unit costs will be used as the justification for a baseline gross avoided costs and an annual allowance will be given based on the company WACC savings against these baseline gross avoided costs. Where flexibility continues to defer the reinforcement, the annual allowance will be provided. Similarly, should flexibility become unviable, then allowances for flexibility can be withdrawn and allowances for conventional reinforcement revised upwards.

7.51. Flexibility costs and the gross avoided cost of reinforcement will be reported in detail within the E6 RRP table, as per ED1. This will be on a per scheme basis for Primary projects over £2 million, linked to EJPs. It will be on an aggregated basis for Primary projects under £2 million and for each unit cost category of Secondary reinforcement. Total costs and volumes will continue to be reported aggregated within RRP tables CV1 and CV2. Whilst data will be reported annually, the flexibility allowance uncertainty mechanism will only be reconciled at the end of the price control, reducing the regulatory burden of additional assessment in the price control.

Strategic investment

7.52. To avoid cutting off any future RIIO-ED3 pathways, we may need to undertake works within the RIIO-ED2 period which otherwise would not be triggered. Similarly, it may be more economically prudent to undertake activity at a different profile ahead of need. WPD has considered these elements and is proposing a number of pathways to take forward this investment.

7.53. There are four pathways WPD is proposing for dealing with strategic investment in the RIIO-ED2 period. These are: Supporting Welsh energy strategy, Stakeholder-led Anticipatory Investment, RIIO-ED3 enabling works identified by DFES and Proactive service unlooping.

Supporting Welsh energy strategy

7.54. WPD is committing to take an enhanced role in supporting Wales in its journey to decarbonisation. During RIIO-ED2, we will leverage our knowledge of UK electricity networks, our understanding of energy system interactions and our significant experience in local area engagement to help the Welsh Government develop, deliver and implement a cohesive national energy strategy that both informs, and is aligned with, LAEPs.

7.55. To achieve a decarbonisation pathway which maximises the regional benefits from the existing infrastructure, a whole system plan must be developed. WPD will work collaboratively across transmission, distribution and gas, and electricity to develop a regional infrastructure blueprint that takes forward the right local options to achieve net zero.

7.56. During an initial two year high level design phase, WPD will support Welsh Government in delivering a regional energy strategy and an infrastructure blueprint. This recommendation for further investment will be presented to Ofgem for consideration of future funding. Depending on the timescales of the required investment, this may be within RIIO-ED2 as part of this uncertainty mechanism, or during future price controls. It may also consider usage of the coordinated adjustment mechanism (CAM). Where additional funding is considered necessary during the RIIO-ED2 period, this can be taken forward through the primary load related expenditure uncertainty mechanism.

7.57. WPD has committed over £2 million in costs to support this activity.

Year	2023/4	2024/5	2025/6	2026/7	2027/8	RIIO-ED2
Costs	£0.42m	£0.42m	£0.42m	£0.42m	£0.42m	£2.1m

Figure SA-06a.36 Costs for supporting a Welsh energy strategy

Stakeholder-led anticipatory investment

7.58. While WPD's Distribution Future Energy Scenarios builds a bottom up, stakeholder informed view of network development, there may be specific areas where stakeholders require development of infrastructure ahead of need to further catalyse their own decarbonisation plans.

7.59. New evidence will be developed during the price control which iteratively affects the WPD Best View, although this may be behind the rapid and accelerated changes in local area plans.

7.60. The ambition to deliver net zero in local areas and the delivery of that ambition across the WPD regions may also begin to lead the national projections set out in the national FES, restricting WPD's ability to recommend additional local investment if it is contingent upon comparisons informed by the national scenarios.

7.61. To enable strategic investment to be brought forward, WPD will engage with stakeholders in 2023, 2025 and 2027 to enable them to submit additional evidence for strategic investment in areas identified as being on the cusp of requiring reinforcement. Stakeholders will also be invited to identify other suitable areas within the WPD regions.

7.62. Assessment criteria will be used to select the most credible and appropriate schemes to take forward to Ofgem for recommendation for strategic investment.

7.63. These schemes will be taken forward by WPD through our primary and secondary load related expenditure uncertainty mechanisms.

RIIO-ED3 enabling works identified by DFES

7.64. Through the RIIO-ED2 period, national, regional or local government decisions may drive additional investment requirements outside of those forecast in the DFES used for the RIIO-ED2 Business Plan. Similarly, consumer uptake or technology improvements may also drive investment requirements upwards.

7.65. Where stakeholder engagement, lagging and leading growth metrics and other market evidence can support an investment being required to be delivered within RIIO-ED2 to support a future pathway through RIIO-ED3, the funding of that investment can be facilitated by the primary and secondary load related uncertainty mechanisms.

Proactive service unlooping uncertainty mechanism

7.66. At the most remote ends of our network, LV services were frequently looped together to reduce the cost of servicing multiple properties in close proximity. The rate at which these services will need to be unlooped has been increasing due to the additional notifications received from the connection of LCTs such as EVs and heat pumps. In line with DFES predicted activity, service unlooping should be considered low regret and least cost to proactively and strategically invest ahead of need where this can be achieved, in order to deliver greater efficiency rather than following a reactive programme.

7.67. For each unlooped service delivered proactively within a programme, we propose for funding to be through a simple symmetrical volume driver with ex-ante unit costs (see figure 7.5). Activity will be disaggregated down to volumes of cut out replacements, underground services unlooped and overhead services unlooped. Volumes of services will be based on MPANs affected. The ex-ante provision will be based on our Best View, which is stakeholder informed and aligned to the DFES. (The output metrics relating to service related strategic investment are given in figure SA-06a.37).

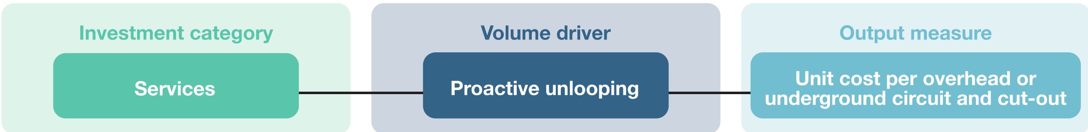

Figure SA-06a.37 Graphic relating output metrics to activity categories for service related

7.68. The proposed automatic symmetrical uncertainty mechanism will be applied annually to the ex-ante allowance. Volumes of activity will be reported through table CV2 in the RRPs. At the end of the price control, TIM will be applied to the actual costs of activity and compared to the allowances based on volumes delivered and ex-ante unit costs.

Incentivising outperformance

7.69. For services, secondary and primary network expenditure, we propose to employ a Totex Incentive Mechanism (TIM) when comparing the ex-ante and uncertainty mechanism-driven allowances against actual costs incurred and outputs delivered at the end of the price control.

7.70. Volumes, scheme costs and unit costs will be used to calculate the allowances versus actual costs within a single regulatory year and the aggregate of this across all activities will be used to determine the application of the TIM.

7.71. The sharing factor used will be determined through the price control and applied to the volumes of activity forecast.

Impact of the Network Access Significant Code Review

Additional Connections Acceptances

7.72. To determine the impact of additional Connections Acceptances during the RIIO-ED2 period a review of recent Connection Offer rejections was undertaken to establish how many were directly due to the level of Reinforcement required and whether the customer would likely return following the implementation of the SCR. Our IT plans include investment in LV Monitoring and smart meter data. We forecast that this will defer over £28 million of connections reinforcement investment, which is therefore excluded from this forecast.

Secondary Reinforcement

7.73. A survey was carried out on a six month data set and was reviewed by Connections Design staff who provided the original connection offer. The value of works flagged as likely to return was then pro-rated up to a full 12 months.

7.74. To establish the value of expenditure for completion of Table M30B the following assumptions were made:

Best View (25% of total expenditure): Best view was deemed to be a 25% return rate as there are many factors that would be considered not just the reinforcement cost that initially put the customer off. There may be planning issues to overcome, the developer/customer may have changed their site/requirement or the site was developed under a revised scheme which did not require so much infrastructure. This is a conservative estimate and may need revisiting as SCR decision is firmed up and more data becomes available.
High Case (100% of total expenditure): High was assumed to be 100% of rejected offers would return.
Low Case (zero % of total expenditure): Low case was determined that the introduction of SCR would not trigger a return of connections offers rejected.

Primary Reinforcement

7.75. The survey was carried out on rejected connection offers over a 2 year period. These offers were reviewed flagged as likely to return. The total value of these schemes was used to calculate the value of Reinforcement and was profiles across the RIIO-ED2 period.

7.76. To establish the value of expenditure for completion of Table M30B the following assumptions were made:

Best View (50% of total expenditure): Best view was deemed to be 50% as the scheme analysed were very specific connections projects so more data was available for an initial review. This view may change as the SCR decision is firmed up and more data becomes available, including newer connection offer data over the remaining years of RIIO-ED1.
High Case (100% of total expenditure): High was assumed to be 100% of rejected offers would return.
Low Case (zero % of total expenditure): Low case was determined that the introduction of SCR would not trigger a return of connections offers rejected.

Transition of non-firm to firm access – Primary

7.77. Analysis of existing customers who are subject to ANM. WPD Best view is that 50% of these customers would request a firm connection. High case is 100% and Low case 25%. The schemes have been reviewed for Flexibility solutions and these costs have been deducted. The subsequent Flexibility costs are reported under Curtailment – primary.

Transition of non-firm to firm access – Secondary

7.78. Analysis of existing customers who are subject to non-firm connections. On the Secondary network, these are largely ANM or Export Limiting schemes. WPD Best view is that 50% of these customers would request a firm connection. High case is 100% and Low case 25%. No allowance has been made for flexibility as this would be negligible.

Curtailment – Primary

7.79. A portion of conventional reinforcement costs assessed under the methodologies above has been taken forward to ascertain the likely economic mix of flexibility markets and conventional reinforcement.

7.80. It is expected that curtailment costs would be market-led and not administered. Curtailment would only be paid where economic to do so, hence the value of the curtailment would be aligned to the benefit of reinforcement deferral. Markets for generation export constraints could be stimulated from the beginning of RIIO-ED2. WPD has already procured generation turn down and demand turn up flexibility under business as usual in its Hawton area, resulting in contracts being awarded.

7.81. The Primary costs under the low, best view and high cases have been deferred by one year, resulting in a portion of the forecast expenditure being deferred out of the price control. Curtailment costs have been added based on the value of the deferral and these have been aligned to start at the beginning of the RIIO-ED2 period, using flexibility markets to accelerate the firmness of connections.

Curtailment – Secondary

7.82. The majority of secondary connected generators which have been enrolled into flexible connections have done so due to Primary or Transmission constraints, therefore no curtailment due to secondary network issues is expected.

7.83. Curtailment costs for secondary connected generation that is curtailed for Primary network constraints is included in the Primary curtailment figures.

Transition of network investment from funded through customer contributions to DUoS funding

7.84. This is the value of Customer Contributions attributed to Customer Reinforcement within the RIIO-ED2 Business plan. For Demand market segments the total value of customer contributions was used but for DG Market Segments historic data was analysed to establish the level of Reinforcement that was either at the same voltage level or a higher voltage level. The % of reinforcement at a higher voltage level was then deducted from the RIIO-ED2 customer contributions at each market segment.

7.85. These values were applied to each of the Best View, High and Low scenarios.

Core Closely Associated Indirects (new work - net increase in work)

7.86. There will be an increase in costs associated with Network Design & Engineering and Project management specifically driven by Additional Customer acceptances. Our assumption for Best View is 25%, High is 100% and Low is zero. This is aligned to our view on Secondary Reinforcement as this is where the volumes are. However we may need to consider additional staff in relation to primary reinforcement should more data become available.

7.87. Network Design staff increase for Best View would be an additional six ND&E and an additional two Project Managers across WPD.

7.88. High case would result in 14 additional ND&E staff and six Project Managers.

Business Support Costs (new work - net increase in work)

7.89. There will be increased costs for Business Support activities such as Finance & Regulation for increased billing activity but at this stage there is not enough information available to accurately assess the staffing impact. As SCR is firmed up and more clear this is an area that we will want to revisit and may only become clear during the RIIO-ED2 period.

SCR Impact Summary Tables

Impact of SCR - Best View						
	2023/24 £m	2024/25 £m	2025/26 £m	2026/27 £m	2027/28 £m	RIIO-ED2 Total £m
West Midlands	11	14	19	27	27	**98**
East Midlands	15	18	22	26	25	**106**
South Wales	4	6	7	8	11	**36**
South West	6	12	15	19	14	**66**
WPD Total	**36**	**50**	**64**	**80**	**77**	**306**

Figure SA-06a.38 Cost summary table for SCR Best View

Impact of SCR - High case						
	2023/24 £m	2024/25 £m	2025/26 £m	2026/27 £m	2027/28 £m	RIIO-ED2 Total £m
West Midlands	22	28	36	52	52	**191**
East Midlands	35	40	48	56	54	**233**
South Wales	7	10	12	13	18	**61**
South West	11	22	28	34	26	**121**
WPD Total	**75**	**101**	**124**	**156**	**150**	**606**

Figure SA-06a.39 Cost summary table for SCR High Case

Impact of SCR - Low case						
	2023/24 £m	2024/25 £m	2025/26 £m	2026/27 £m	2027/28 £m	RIIO-ED2 Total £m
West Midlands	7	9	12	15	15	**57**
East Midlands	7	9	12	14	13	**56**
South Wales	3	4	5	5	7	**25**
South West	4	6	7	9	9	**36**
WPD Total	**22**	**28**	**36**	**44**	**44**	**174**

Figure SA-06a.40 Cost summary table for SCR Low Case

8. Load related expenditure summary

8.1. WPD's load related investment plan summary is shown in figure SA-06a.41[22].:

Total					
£m, 20/21 prices	**West Midlands**	**East Midlands**	**South Wales**	**South West**	**WPD Total**
RIIO-ED1 Annual Average	31	39	8	13	91
RIIO-ED2 Annual Average (forecast)	48	65	33	43	189
RIIO-ED2 Total (5 years)	242	323	164	217	946

Figure SA-06a.41 Load related reinforcement expenditure across each of WPD's four licence areas in RIIO-ED1 and RIIO-ED2

8.2. A list of all load related schemes over £1 million planned during RIIO-ED2 under our Best View is given for each licence area in figures SA-06a.42, SA-06a.43, SA-06a.44 and SA-06a.45 below.

EJP Number	Name	Cost (£/m)	Description
EJP122	Coventry 132kV Fault level Reinforcement	16	Replant 132kV switchgear in-situ at Coventry GSP.
EJP123	Willington 132kV Fault level Reinforcement	15.6	Replant 132kV switchgear offline at Willington GSP.
EJP131	Northampton Group 132kV Circuit Reinforcement	10.984	8km 132kV UG cable from Grendon GSP to Northampton East BSP & 132kV bay at Grendon GSP.
EJP140	Harbury to Banbury 132kV Circuit	10.216	20km wood pole 132kV OHL from Harbury BSP to Banbury BSP.
EJP132	Derby South to Spondon 132kV Circuit Reinforcement	7.948	7km 132kV UG Circuit from Derby South to Spondon.
EJP135	Sharnbrook 33/11kV Substation Reinforcement	6.413	Add second transformer and new 33kV circuit at Sharnbrook PSS.
EJP130	Clipstone 33kV network Reinforcement	5.268	Build two new circuits from Clipstone, one to Ollerton & one to Thoresby. Total of 18km new 33kV underground circuit.
EJP175	Holbeach and Long Sutton Reinforcement	4.494	Build a new primary substation between Holbeach and Long Sutton.
EJP138	Harbury BSP Reinforcement	3.949	Install a third grid transformer and uprate 132kV circuits to Harbury BSP.
EJP139	Whitwell BSP Reinforcement	3.754	Uprate grid transformers at Whitwell BSP.
EJP171	Wingerworth 33/11kV Substation Reinforcement	3.489	Install a second transformer and new 33kV circuit at Wingerworth PSS.
EJP137	Grassmoor 33/11kV Substation Reinforcement	3.48	Uprate transformers and build two new 33kV circuits to Grassmoor PSS.
EJP170	Ratcliffe to Loughborough Tee 132kV Cable Reinforcement	3.101	Asset transfer and uprating of sections of 132kV UG cable out of Ratcliffe-on-Soar GSP.

[22] This represents load related expenditure including general primary and secondary reinforcement, connections related reinforcement, fault level reinforcement and new transmission connections charges; and is net of customer contributions. This is consistent with the presentation in supplementary annex SA-06 Expenditure

EJP166	Ellesmere Avenue 33/11kV Substation Reinforcement	3.014	Replace both transformers at Ellesmere Avenue PSS.
EJP167	West Bridgford 33/11kV Substation Reinforcement	2.854	Upgrade both transformers and circuits (6km UG) at West Bridgford PSS.
EJP129	Rugby 33kV Fault level Reinforcement	2.801	Uprate 33kV switchgear at Rugby BSP to increase fault level rating.
EJP133	Woodbeck 33/11kV Substation Reinforcement	2.769	Add second transformer and circuit from Ordsall Road PSS to Woodbeck PSS.
EJP134	Winster BSP Reinforcement	2.721	Upgrade both grid transformers at Winster BSP.
EJP173	Northampton BSP Reinforcement	2.561	Install a third grid transformer at Northampton BSP.
EJP136	Ilkeston 33/11kV Substation Reinforcement	2.086	Replace both transformers at Ilkeston PSS.
EJP174	Atherstone 33/11kV Substation Reinforcement	2.051	Replace both transformers and 33kV feeder circuits at Atherstone PSS.
EJP168	Holme Carr 33/11kV Substation Reinforcement	1.919	Replace both transformers & 11kV Switchboard at Holme Carr PSS.
EJP172	Ambergate 33kV Network Reinforcement	1.612	Uprate 33kV circuits between Wessington PSS, Ambergate PSS and Ravensdale Park PSS.
EJP169	Staythorpe to Hawton 132kV Circuit Reinforcement	1.416	Reconductor the 132kV DE route to Hawton BSP.
EJP114	Staythorpe GSP Reinforcement	1.182	New SGT and expand bar at Staythorpe GSP.

Figure SA-06a.42 Load related reinforcement EJP list for East Midlands Best View schemes

EJP Number	Name	Cost (£/m)	Description
EJP162	Shrewsbury Group 33kV Circuit Reinforcement - New Shelton 33/11kV Substation	11.004	Install a new 33/11kV substation at Shelton PSS with two new 8km 33kV circuits being installed to feed this site.
EJP156	Ludlow to Presteigne 66kV Circuit Reinforcement	7.920	Build a new 132/66kV infeed at Ludlow BSP and a new 66kV circuit to Presteigne PSS.
EJP159	Ironbridge to Star Aluminium 33kV Circuit Reinforcement	6.045	Lay approximately 20.5km of 33kV cable between Ironbridge BSP and Star Aluminium PSS.
EJP126	Chipping Sodbury BSP Reinforcement	5.707	Build a new 132/33kV single transformer BSP situated adjacent to Iron Acton GSP.
EJP128	Meaford BSP Reinforcement	5.542	Install a 132/33kV transformer at Meaford BSP and extend Barlaston 6 corner mesh.
EJP164	Lea Marston to Copt Heath 132kV OH Reinforcement	4.299	Reinforce the 132kV OHL circuits between Lea Marston and Copt Heath.
EJP120	Kitwell 132kV Fault Level Reinforcement	3.858	Replace the circuit breakers on the 132kV busbars at Kitwell BSP.
EJP113	Shrewsbury GSP Reinforcement	3.494	Install a second SGT at Shrewsbury GSP and extend the 132kV busbar.
EJP127	Lea Marston to Elmdon 132kV Circuit Reinforcement	3.099	Reinforce the 132kV OHL circuits between Lea Marston and Elmdon.
EJP158	Hill Chorlton 33/11kV Substation Reinforcement	2.672	Add a second transformer and 9km circuit at Hill Chorlton PSS.

EJP Number	Name	Cost (£/m)	Description
EJP157	Stockton 33/11kV Substation Reinforcement	2.518	Add a second transformer and 11km circuit at Stockton PSS.
EJP161	Sutton Coldfield 132/11kV Reinforcement	2.484	Construct a new switchroom and replace switchgear to allow board expansion at Sutton Coldfield 132/11kV.
EJP163	Stowfield to St Weonards Reinforcement	1.709	Install a new 33/11kV transformer at Stowfield PSS and reinforce the 11kV interconnection between Stowfield and St Weonards.
EJP160	Halesowen 132/11kV Reinforcement	1.688	Construct a new switchroom and replace switchgear to allow board expansion at Halesowen 132/11kV.
EJP165	Coseley 132/11kV Substation Reinforcement	1.571	Construct a new switchroom and replace 11kV switchboard and circuit breaker at Coseley 132/11kV.
EJP119	Bustleholm 132kV Fault Level Reinforcement	1.487	Replace the 132kV isolators at Bustleholm GSP.
EJP121	Wolverhampton 33kV Switchgear Reinforcement	1.421	Replace the existing 33kV switchboard at Wolverhampton BSP.

Figure SA-06a.43 Load related reinforcement EJP list for West Midlands Best View schemes

EJP Number	Name	Cost (£/m)	Description
EJP185	Camborne/Hayle BSP Group Reinforcement	19.256	Extend the busbars at Camborne and Rame and build a new 132kV circuit.
EJP191	Isles of Scilly 2nd 33kV Subsea Cable	11.302	Install a second 33kV subsea cable from the mainland to the Isles of Scilly.
EJP148	Feeder Road BSP Reinforcement	7.413	Build a new 132/11kV BSP to deload Feeder Road BSP 33kV and St Pauls BSP 11kV.
EJP149	Exeter City BSP Reinforcement	6.224	Build a new BSP in Matford in Exeter.
EJP124	Exeter Main GSP 132kV Fault level reinforcement	5.139	Fault level reinforcement at Exeter Main GSP.
EJP125	Indian Queens GSP 132kV Fault Level Reinforcement	4.703	Fault level reinforcement at Indian Queens GSP.
EJP187	Mullion 33/11kV Substation Reinforcement	3.605	Add a second transformer, new switchboard and 33kv circuit at Mullion PSS.
EJP118	Alverdiscott/Indian Queens GSP Group Reinforcement – New GSP and BSP	2.772	Commission a new GSP south of Pyworthy and a new BSP on the K Route (25% in RIIO-ED2).
EJP146	Morwenstow 33/11kV Substation Reinforcement	2.439	Add a second transformer, new switchboard and 33kV circuit at Morewenstow PSS.
EJP184	Witheridge 33/11kV Substation Reinforcement	2.350	Add another transformer and replace the switchboard at Witheridge PSS.
EJP190	Newquay - Trevemper 33kV circuit	2.339	Build an additional 33kV circuit between Fraddon and Newquay Trevamper.
EJP192	Hayle BSP Reinforcement	2.125	Replace both grid transformers at Hayle BSP.

EJP Number	Name	Cost (£/m)	Description
EJP186	Gunnislake Primary 33/11kV Substation Reinforcement	1.604	Replace both transformers at Gunnislake PSS.
EJP188	St Tudy - Davidstow 33kV Circuit Reinforcement	1.284	Upgrade 17.5km of 33kV circuit between St Tudy and Davidstow.
EJP189	St Mawgan 33/11kV Substation Reinforcement	1.222	Add another transformer and replace the switchboard at St Mawgan PSS.
EJP150	Landulph BSP Reinforcement	1.119	Replace GT2 at Landulph BSP with a 90MVA unit.
EJP147	Countess Wear 33/11kV Substation Reinforcement	1.069	Install a second 33/11kV transformer at Countess Wear.
EJP151	Chewton Mendip 33/11kV Substation Reinforcement	1.028	Add a second transformer at Chewton Mendip PSS.

Figure SA-06a.44 Load related reinforcement EJP list for South West Best View schemes

EJP Number	Name	Cost (£/m)	Description
EJP182	Mid Wales 66kV Circuit Reinforcement (Abergavenny Northern Ring)	30.320	Establish a new 132kV UG circuit from Rassau to near Brecon PSS to feed a new BSP.
EJP144	Upper Boat - Mountain Ash, Dowlais and Merthyr East 132kV Circuit Reinforcement	20.357	Reconductor the Y, YE and D 132kV dual OHL circuit routes.
EJP179	Pembroke 132kV Network Reinforcement	15.863	Build a new 132kV cable circuit into Milford Haven BSP from Pembroke BSP.
EJP116	Hirwaun GSP	4.097	Establish a new GSP in the Hirwaun area.
EJP117	Ferryside GSP	3.586	Establish a new GSP in the Kidwelly/New Lodge/Meinciau area (known as Ferryside).
EJP178	Haverfordwest to Brawdy 33kV Circuit Reinforcement	3.496	Build a new 33kV circuit from Haverfordwest BSP to Brawdy PSS.
EJP181	Establishment of Third 132kV Circuit from Swansea North GSP to Rhos BSP	3.496	Install 3km of 132kV UG circuit which (by utilising existing assets) will establish a third 132kV circuit from Swansea North GSP and Rhos BSP.
EJP142	Usk Way 33/11kV Substation	3.217	Build a new primary substation on previously purchased land in Newport City.
EJP145	Llanfyrnach 33/11kV Substation Reinforcement	2.860	Install a second 33kV circuit from St Clears to Llanfyrnach and install a second 33/11kV transformer, associated switchgear and a new 11kV switchboard.
EJP115	Llanfoist GSP	2.792	Establish a new GSP in the Llanfoist area.
EJP177	Cardiff North 33kV Network Reinforcement	2.274	Establish two new 3.5km 33kV underground circuits between Cardiff North BSP and Heath PSS. This will split the 33kV networks between Cardiff East and Cardiff North.
EJP180	Hirwaun to Aberdare No 2 33kV Circuit Reinforcement	2.215	Upgrade the Hirwaun to Aberdare no. 2 circuit and complete associated switchgear

EJP Number	Name	Cost (£m)	Description
			works, as well as replace the existing T1 at Aberdare PSS.
EJP176	Cardiff East to Cardiff North BSP Demand Transfer	2.089	Install a new 33kV underground circuit from Cardiff North BSP to Cyncoed PSS to allow Cyncoed to be transferred onto Cardiff North BSP.
EJP143	Abergavenny 132/66kV Substation Reinforcement	1.209	Upgrade Abergavenny 132/66kV GT1 from a 60MVA to a 90MVA unit.
EJP183	Ravenhill 33/11kV substation Reinforcement	1.133	Upgrade T2 at Ravenhill PSS from 10/14MVA to 12/24MVA.
EJP141	Rhos BSP Reinforcement	1.121	Install a second grid transformer at Rhos BSP.

Figure SA-06a.45 Load related reinforcement EJP list for South Wales Best View schemes

8.3. A number of EJPs also describe load related investment which spans all four of WPD's licence areas. These are listed in figure SA-06a.46 below.

EJP Number	Name	Cost (£m)	Description
EJP112	Secondary Reinforcement Programme	373.9	Load related secondary reinforcement works will be carried out across all four licence areas.
EJP152	Flexibility Procurement	9.756	Flexibility procurement will be used to defer conventional reinforcement expenditure across a number of schemes for all four licence areas. Some schemes will be deferred within RIIO-ED2 and some will be pushed out of the price control period altogether.
EJP153	ANM Schemes	7.2	Active Network Management will be used to manage a number of constraints in all four licence areas.
EJP154	Fixed Power Quality Monitoring Equipment Installation Programme	6.4	WPD plans to install Power Quality (PQ) monitoring devices at 132kV substations across all four licence areas.
EJP155	Low Frequency Demand Disconnection (LFDD) Optimisation	15.806	Reinforcement of the Low Frequency Demand Disconnection (LFDD) scheme across all four licence areas is necessary to ensure effective restoration of electricity system frequency, when called upon to operate.

Figure SA-06a.46 WPD wide load related EJP list

9. Appendices

Appendix A01 - Distribution Future Energy Scenarios (DFES) Reports

9.1. Since 2015, we have been creating Distribution Future Energy Scenarios (DFES) reports. From 2020, our System Operator team is producing reports annually to forecast rapidly-changing low carbon technology uptakes up to 2050. The DFES projections have been aligned to the latest National Electricity System Operator (ESO) scenario forecasts which are available when the DFES process is carried out.

9.2. The reports can be found on our website at:

East Midlands Report: https://yourpowerfuture.westernpower.co.uk/downloads-view/42042
South Wales Report: https://yourpowerfuture.westernpower.co.uk/downloads-view/42039
South West Report: https://yourpowerfuture.westernpower.co.uk/downloads-view/42036
West Midlands Report: https://yourpowerfuture.westernpower.co.uk/downloads-view/42033

Appendix A02 - DFES: Customer Behaviour Profiles and Assumptions Report

9.3. The Distribution Future Energy Scenarios outline the range of credible futures for the growth of the distribution network. Broadly aligning with the National Grid Future Energy Scenarios, these encompass the growth of demand, storage and distributed generation, also LCTs such as electric vehicles and heat pumps.

9.4. To determine the electrical behaviour, we use data drawn from innovation projects and measured network loadings to determine future consumption patterns. We update and publish these factors regularly.

9.5. They can be found on our website at: https://yourpowerfuture.westernpower.co.uk/downloads-view/42030

Appendix A03 - DFES: Stakeholder Consultation Summary Reports

9.6. A key part of the DFES is engagement and consultation with local stakeholders. Regen consults with local authorities to translate local development plan data into detailed scenarios of connections to the WPD distribution network. This report collates the results of four stakeholder consultation webinars, run by Regen and WPD as part of the 2020 Distribution Future Energy Scenarios (DFES) project. This report includes the audience comments and questions, as well as the stakeholder feedback on the questions which were asked of the audience live.

9.7. The reports can be found on our website at:

East Midlands Report: https://yourpowerfuture.westernpower.co.uk/downloads-view/42027
South Wales Report: https://yourpowerfuture.westernpower.co.uk/downloads-view/42024
South West Report: https://yourpowerfuture.westernpower.co.uk/downloads-view/42021
West Midlands Report: https://yourpowerfuture.westernpower.co.uk/downloads-view/42018

Appendix A04 - Distribution Network Options Assessment Report

9.8. The Distribution Network Options Assessment (DNOA) outlines investment decisions made by WPD in order to deal with constraints that arise across our licence areas. This includes DSR procured through WPD's Flexible Power, conventional reinforcement schemes and innovative solutions such as ANM. To determine the economically optimal solution, cost-benefit analysis is carried out which is described in the DNOA. By outlining our analysis process stakeholders and customers can be assured that WPD is giving them the best possible value for money while maintaining a secure and sustainable network.

9.9. The DNOA also works in tandem with Flexible Power in helping inform flexibility providers of the potential for future opportunities to provide flexibility services with signposting data for the next 5 years.

9.10. The DNOA is published on our website at https://yourpowerfuture.westernpower.co.uk/downloads-view/42015

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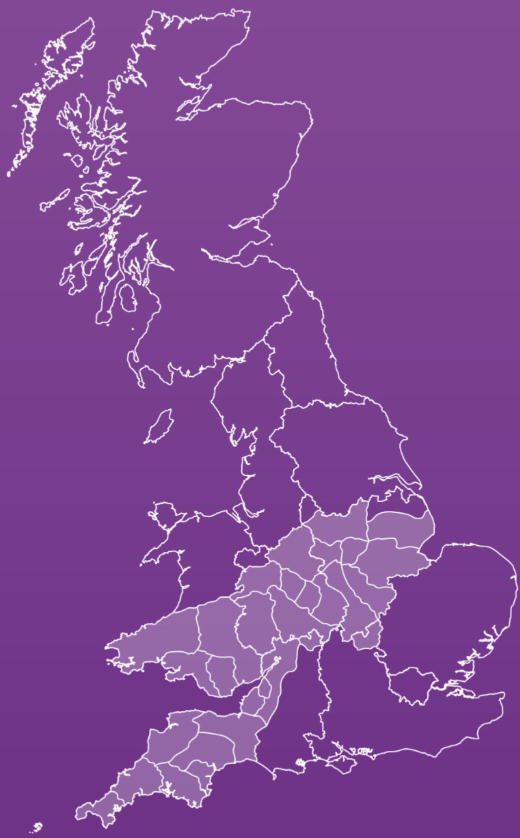

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