Demand Uncertainty on Low Voltage Distribution Networks: Analysing the Use of Distribution Future Energy Scenarios (DFES) in Network Company Business Plans

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Abstract

The net zero transition is expected to involve significant investment in low carbon technologies (LCTs) that enable the electrification of transportation and heating loads. However, there is uncertainty around the temporal and geographical dispersion of technologies such as electric vehicles and heat pumps, which, as they require connection to the low voltage distribution networks, will pose challenges for system operation and will most likely require significant investment in new network capacity. By investigating the current approach to network planning and load-related investment in Britain's electricity distribution network, we analyse and discuss how the network companies and the regulator – Ofgem – are dealing with this uncertainty in practice. We outline a new approach to load-related network planning which has been implemented by the electricity DNOs and we follow how this scenario-based approach has been integrated into their business plans and long-term investment appraisal frameworks. Based on interviews with industry participants, we also discuss scenario-based planning in the context of Ofgem's price control review process and its potential role in revealing information about cost efficiencies and 'smart' approaches to the integration of LCTs at the local level. Finally, we discuss how findings from our research can inform ongoing discussions about regulatory reform and the role of Britain's Future System Operator in planning network transformations at the regional and local levels.

1 Introduction

Britain's electricity distribution networks are organised around fourteen regions and operated by six private distribution network operators, or DNOs (Figure 1). The DNOs hold licenses to own and operate the networks, and as natural monopolies, their businesses are regulated as part of multi-annual 'price control reviews'. Under this regime, the independent regulatory agency, Ofgem, caps their revenues ex-ante and incentivises them to operate their businesses efficiently whilst delivering certain outputs.

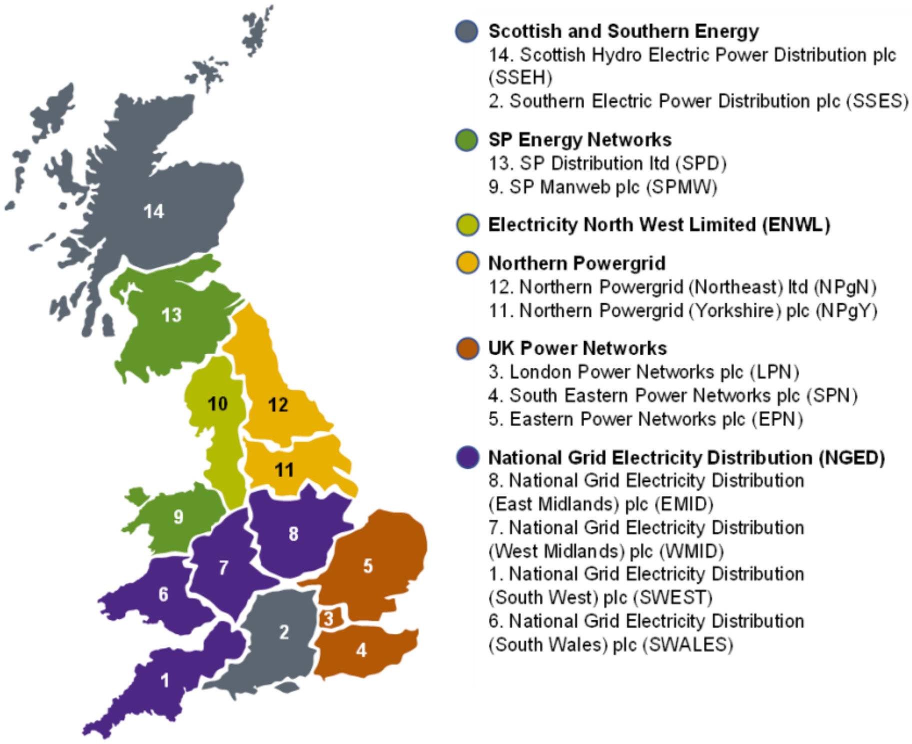

Figure 1: Distribution Network Operators (DNOs) and their licence areas in 2023 (source: Ofgem, 2022a)

The early price controls following privatisation were done according to the RPI-X approach, with prices changing according to RPI – the retail price inflation index – and X – an adjustment to prices to reflect expected efficiency savings. In line with the incentive regulation philosophy, companies were allowed to retain any efficiency gains beyond the regulator's expectation (re: Littlechild, 1983). In the early years of network regulation, network planning was reasonably predictable. However, the regulator relied on company-based forecasts and, rightly, had concerns about information asymmetry, which raised concerns about gaming and created difficulties for the regulator in setting the appropriate revenue levels (Crouch, 2006).

Capital investment needs were growing during the 2000s due to asset depreciation, but also increasing demands on the network companies to ensure that decentralised energy generation was able to connect to the networks. Through the following price controls, from 2005-2015, the regulator gradually introduced mechanisms to reduce investment uncertainty and information asymmetry (Crouch, 2006). An increasingly important consideration in these regulatory reviews has been each company's business plan which sets out a DNO's view of the expenditure on operations and capital investment required to deliver network services. As a result, the regulator has introduced further licence obligations on the companies to develop accurate business plans (Crouch, 2006).

Recognising the major changes required to meet the net zero target, in RIIO ED2 (the second RIIO price control for electricity distribution running from 2023 to 2028),[1] the regulatory framework became more customer focussed, with customer and stakeholder engagement required by the regulator to form the basis for business planning. Company-based Customer Engagement Groups and a centrally based Challenge Group were introduced to provide 'challenge' to the companies that business strategies and investment decisions had a basis in customer and stakeholder preferences (Ofgem, 2019). As well as producing more customer focussed business plans, customer engagement was also expected to feed into network planning, with a minimum requirement in the Business Plan Incentive (discussed in more detail below).

Furthermore, all load-related expenditure – the proportion of investment required to meet new demands – is now required to be based on regionalised versions of the National Grid Electricity System Operator's (NGESO) 2050 scenarios: the Future Energy Scenarios (FES) (e.g. National Grid ESO, 2023) (Figure 2). These scenarios involve assumptions about the level of societal engagement in the net zero transition, influencing the speed of uptake of LCTs. In order to develop plausible regional scenarios based on the FES framework, the DNOs have had to undertake extensive stakeholder engagement and to develop an understanding of demand patterns on their systems, to a much greater extent than was required in previous iterations of the price controls.

It has been estimated that to realise the electrification of transport and heating demands a total infrastructure investment of £300-430 billion will be required. The 'Smart Systems and Flexibility Plan' (BEIS and Ofgem, 2021) outlines that in order to keep this in the lower range, the use of demand-side technologies and other smart systems will be crucial. In this context, a new challenge in developing DNO business plans is uncertainty around the diffusion patterns of low carbon technologies (LCTs), both in terms of the timing and geographical patterns of consumer uptake of heat pumps and electric vehicles, and whether these technologies will be used in ways which enhance the flexibility of the system.

Diffusion patterns will be influenced by consumer preferences, government policy, economic growth, the rate of technological change, local energy plans, and a range of other variables. Moreover, due to the successive waves of pre- and post-war housing construction and deindustrialisation in some regions, available capacity on the low voltage networks is not uniform. Due to these historical factors and limitations of IT monitoring systems, there is a general lack of knowledge about the state of the networks below the local substation level (Bell and Hawker, 2015).

In this paper, we investigate and discuss how the electricity distribution networks and Ofgem are approaching investment planning as we enter a period of great uncertainty about future demands on these regional and local systems. Our main research question is as follows: 'How do distribution network operators (DNOs) and the regulator deal with the increasing uncertainty around future demand on the low voltage networks and what are the implications

[1] Revenue = **I**nnovation + **I**ncentives + **O**utputs – companies were expected to use innovation to achieve incentives across a range of outputs

for long-term network planning and future regulation?'. Using a combination of document analysis and expert interviews,[2] we outline the emergence of a standardised approach to scenario planning across the sector and discuss how new approaches to demand forecasting are being integrated with investment appraisal, business planning and the regulator's price control review framework.

The remainder of the paper is structured as follows: Section 2 outlines how DNOs have been approaching the issue of uncertainty in future demands and developing a new forecasting approach based on the four FES scenarios - Figure 2 below summarises the FES framework and scenarios. Section 3 discusses how this novel planning approach is being incorporated into Ofgem's price control framework; and Section 4 reflects on the results of this research in the context of regulatory reform and future system planning for net zero. An understanding of these recent developments within the electricity distribution sector, we argue, provides some clues as to the future direction of energy planning practices and regulation in the context of decarbonising electricity supply and phasing out fossil fuel use in the transport and heating sectors.

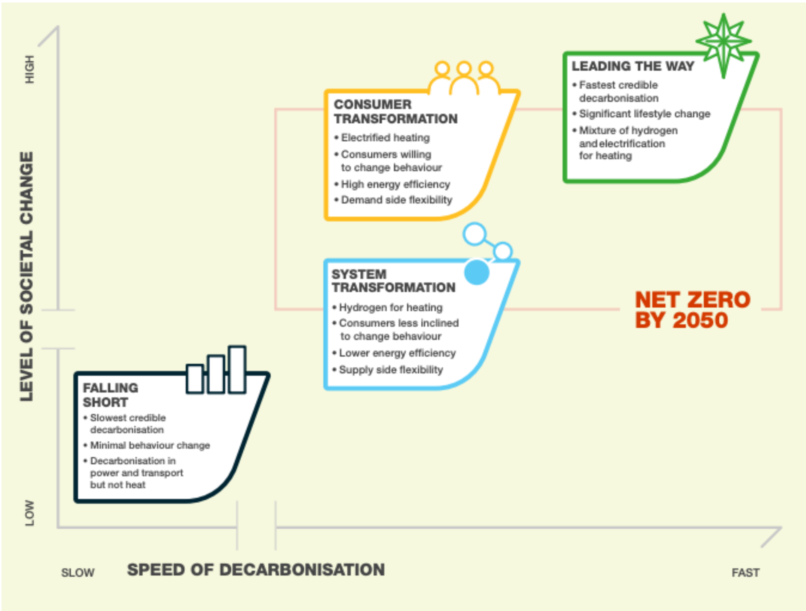

Figure 2: Future Energy Scenarios

[2] Interviews were undertaken with representatives of the six distribution networks, energy consultancies, the Energy Networks Association (ENA), the Electricity System Operator (ESO) and Ofgem.

2 Developing Distribution Future Energy Scenarios

2.1 A common methodology

In 2020, as part of the Energy Networks Association (ENA) Open Networks initiative (Energy Networks Association, 2020), the six DNOs, alongside NGESO and Ofgem, agreed to standardise a Distribution Future Energy Scenario (DFES) approach and designed a common methodology framework, an outline of which is shown in Figure 3.

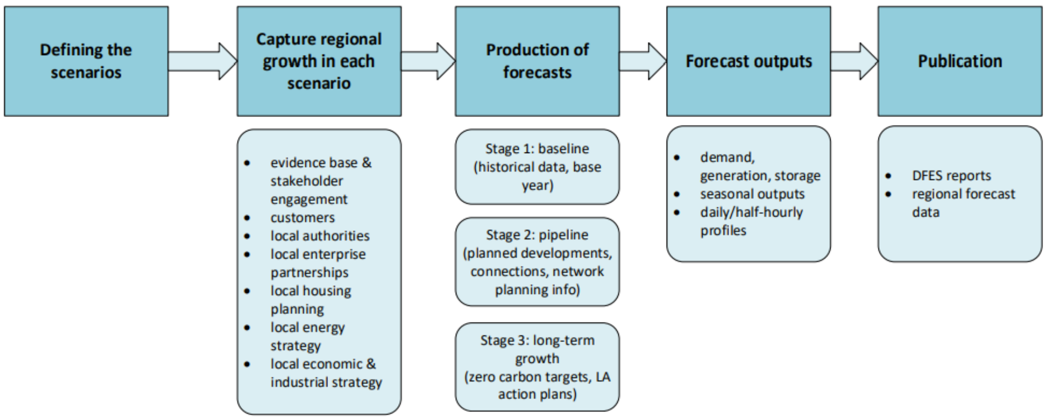

Figure 3: Common DFES methodology framework as agreed by the six DNOs and NGESO (source: Energy Networks Association, 2022a)[3]

Ofgem played a role, initially, in setting out the parameters and defining the scope of the scenarios. Due to concerns about fragmentation and potential gaming via a purely decentralised approach, Ofgem decided to have the DNOs use a common set of net zero compliant forecast assumptions, outlined in the business plan guidance, in advance of the deadline for submitting draft business plans by the end of 2021 (Ofgem, 2021a). These assumptions were to be consistent with the Climate Change Committee's (CCC) 6th carbon budget, the FES, and key government policies such as the Energy White Paper (BEIS, 2020) and the Net Zero Strategy (BEIS, 2021). The latter included a timeline for ending sales of petrol and diesel cars and a national heat pump roll out. Ofgem provided data from the FES and CCC pathways on outline assumptions for demand growth, peak demands, and penetration of EVs and heat pumps up to 2030 (Ofgem, 2021a, pp. 38–43).

In order to meet the second stage of the agreed methodology, the network companies needed to engage more closely with their stakeholders than would traditionally have been the case in developing a business plan. A key challenge identified by our interviewees who participated in this process was the incorporation of local authority decarbonisation plans in the load forecasts, which are a major component of understanding future changes in the network licence areas. While many local authorities have been developing net zero plans, for example through the Local Area Energy Planning (LEAP) approach, potential discrepancies between ambition and actual delivery was an uncertainty which needed to be incorporated into the DFESs. As one interviewee noted, being able to review previous scenarios helped the networks identify those LAs who were able to match their ambition. However, in draft

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[3] This framework was an output of the ENA's Open Networks workstream 1B product 2.

determinations, Ofgem had concerns that some companies had not produced sufficient evidence of how local authorities had influenced their plans, or if a credibility assessment had been undertaken.

As well as the difficulties associated with including the LAEPs, there was a recognised lack of in-house expertise in the methods needed to assess the type of regional growth required by the DFES. The DNOs have used consultants for similar load forecasting work in the past, and so again engaged consultancies to 'regionalise' the scenarios and incorporate bottom-up data from large consumers, the local authorities and other key stakeholders. Three consultancies were awarded contracts by the DNOs: National Grid Electricity Distribution (NGED) and Scottish and Southern Electricity Networks (SSEN) employed Regen; Electricity North West (ENWL), Northern Powergrid (NPg) and UK Power Networks (UKPN), Element Energy; and Scottish Power Energy Networks (SPEN), Baringa. The consultancies reported to the networks on the numbers of expected heat pumps, electric vehicles and other low-carbon technologies in their respective areas. The networks then converted the numbers of LCTs forecasted into expected demand data using known type profiles, such as different EV charger types. Although the DFES is based on a common methodology, basic assumptions and scenarios, there were inconsistencies in how these were utilised and interpreted by the DNOs. In draft determinations on the provisional business plans, Ofgem identified discrepancies in the assumptions used by some networks to convert the numbers given by the consultants into capacity, e.g. for the EV charging types, citing insufficient justification for the data provided (Ofgem, 2022b).

A degree of variation across the different regions is unsurprising given the different geographical contexts, network configurations and the fact that that the companies needed to draw on local stakeholder input in developing the scenarios. For example, both Baringa's (SPEN) and Regen's (NGED) methodologies were based on the assumption that heat pump deployment is strongly affected by gas network availability (Baringa, 2021; Regen, 2022a): While Baringa assumed that in the SPEN area, heat pump diffusion is driven by new builds as most people are connected to the gas-grid (Baringa, 2021), for NGEDs South West licence area, heat pump uptake is driven in the near term by off-gas grid homes switching from other fuels to electrification (Regen, 2022b). However this is not homogenous across NGEDs licence areas as for NGED South Wales, there is more alignment with Baringa, as this area has a lower percentage of off-gas grid homes (Regen, 2022c).

To demonstrate that discrepancies are due to regional variation rather than error, the network companies needed to fully justify their modelling results. This appraisal of the information provided to the regulator was part of the newly introduced Business Plan Incentive, a four stage appraisal of the both the quality of the plans and accuracy of costings contained within them. Companies risked being penalised if their modelling justifications were not sufficiently evidenced. The first stage assessed the quality of information where the network companies were required to meet a range of minimum requirements or receive a 0.5% penalty on their revenue allowance. The second stage assessed the consumer value propositions of the Business Plans and offered a further possible reward, with Stages Three and Four using the quality assessment to allow Ofgem to either impose penalties or reward companies based on either a low or high confidence cost assessment (Ofgem, 2021a). The Business Plan Incentive is the major output incentive in the current RIIO-ED2 price control, covering 2023-2028.

Although Ofgem may have had reservations about some aspects of the business plans, with some companies not passing the minimum requirements in a number of areas (Ofgem, 2022a), all companies passed Stage One. Where Ofgem had not been satisfied with their evidence, the regulator was of the view that the materiality, number and scope of those failures were not sufficient to warrant an overall failure of the Business Plan Incentive (Ofgem, 2022c).

2.2 Demand forecasting and the investment planning architecture

As a number of our interviewees point out, the use of DFES as a forecasting tool has become increasingly important for underpinning decisions about load related expenditure – spending associated with new demand that is likely to increase significantly as transport and heating is electrified:

'*the DFES completely informed all of our load related expenditure for the ED2 business plan' (interview, DNO)*

'the importance of DFES I would say is that it shows you what drives the load related investment that one can find in LTDS (long-term development statement) and then the NDP (network development plan' (interview, DNO).

'*I remember during the business plan process initially we thought the LRE [load related expenditure] paper wouldn't be so big and you know just take the forecast, put it out there, great, job done and then it grew, it grew arms and legs ………it ended up being one of the biggest parts, I think, of the plan' (Interview, DNO)*

Underpinned by the DFES, the distribution networks now produce a range of interlinked development plans and forecasting tools. These tools are then used by the companies to assess options for network constraints that feed into the load-related expenditure requests in their company business plans. The figure below (Figure 4) summarises the relationships between the DFES scenarios and the network plans over different timeframes. A key outcome is a 'best view' scenario that is submitted to the regulator in advance of each price control review and used as a basis for a company's overall strategy in the business plan. The sections below the diagram explain this new and evolving network planning architecture in more detail.

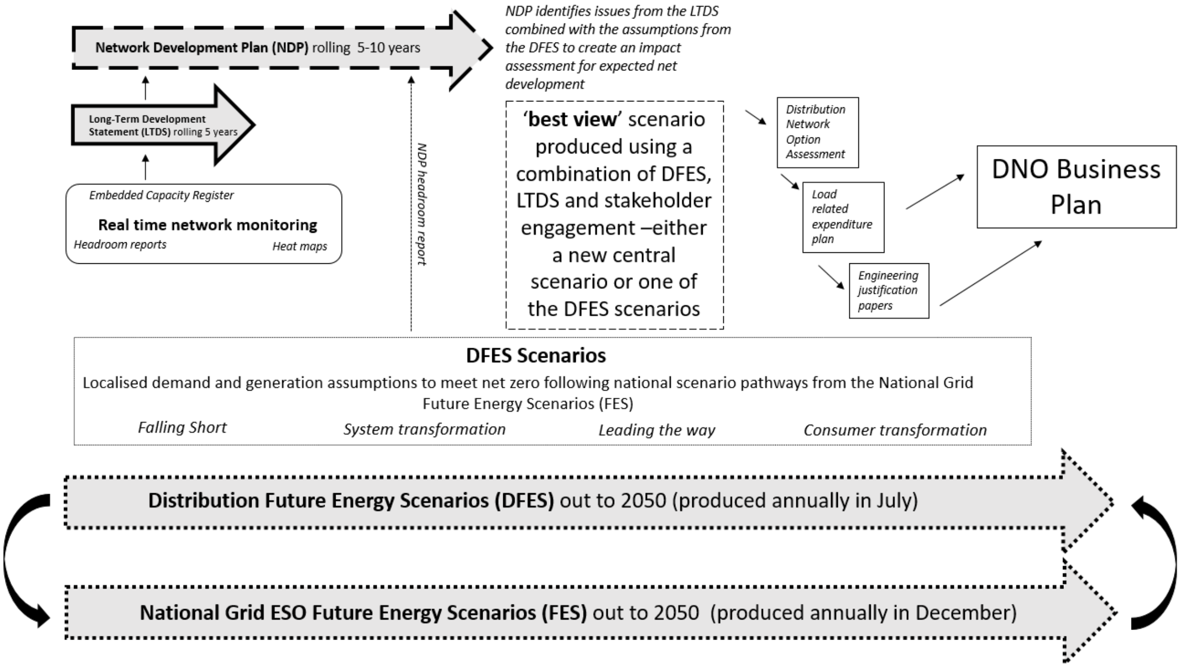

Figure 4: Network planning and modelling for load-related expenditure in electricity distribution network company Business Plans.[4]

The Long Term Development Statements (LTDS) were formally introduced as a licence condition in 2005, although the DNOs had been producing them since 2002 (Ofgem, 2005). The purpose of the LTDS is to give prospective network customers information on the capacity of the network for connection, with visibility provided over a five year timeframe. The network companies produce a statement annually in November, with updates provided in May of known development, combined with a demand forecast for two years and pipeline projects out to five years. This allows for a reasonably certain assessment of opportunities for prospective customers and highlights potential capacity issues.

The Network Development Plan (NDP) was introduced as a licence condition in April 2021 with the first NDPs published in 2022. Their main purpose is to link the demand forecasting and analysis of capacity availability with an appraisal of investment options in the networks – a 'network options assessment'. The NDPs are produced every two years before May 1st and consist of three sections: (i) the *Network Development Report* providing in-depth information to stakeholders on upcoming key projects over a 5-10 year timeframe; (ii) the *Network Scenario Headroom Report* to indicate future capacity availability and possible flexibility requirements based on DFES scenario forecasts; and (iii) the NDP methodology document to provide transparency of the calculations used in the reports (Gas and Electricity Markets Authority, 2023). Working with the DNOs and Ofgem, the Electricity Networks Association produces a Form of Statement so there is alignment in terms of the common methodology and consistency of its implementation across each of the DNOs (Electricity Network Association, 2022).

[4] The solidity of the lines shows the levels of certainty in the modelling. For example, the LTDS and its relationships are a solid line as these are based on real-time monitoring of the networks, whereas the DFES uses dotted lines as these are primarily based on scenario modelling of expected consumer behaviour.

The purpose of the NDP is to visualise a long-term and efficient trajectory for the networks, as the regulator explained, to enable '*a more efficient development of the network rather than just enabling us to set prices* (Ofgem).' Although both the LTDS and the NDP are forecasting tools, the main difference as described by one interviewee is that '*the long-term development statement does include a nought to five-year forecast on a per primary and per grid supply point basis but it doesn't necessarily include any net development'* or *'include a bit of network analysis to say how we're going to fix the problems' (Interview, DNO)*. Therefore, the NDP has an important role within company planning to justify their load-related expenditure. The networks rely on the DFES and NDP processes to establish the needs case. The NDP has been useful not only for the near term but also for showing how load-related expenditure fits into a longer picture than is covered by the price control period. As argued by one DNO interviewee, this could help to make the case for strategic investment, ahead of need:

'*that there is a requirement for investment ahead of need because, well, if there was unlimited resource maybe it would be OK, but we're not going to be able to backload all of our investment in networks to between 2040 and 2050 if we want to hit net zero, we need to be able to try and start doing some things ahead of time.' (Interview, DNO).*

As part of the NDP headroom report based on the multiple DFES scenarios, the companies also provide a medium-term prediction, or 'best view', covering the period from the end of the LTDS out to ten years. Each of the companies chooses a single scenario of reasonable certainty, which can be either a new scenario or one of the DFES scenarios. The aim of the 'best view' is to provide each DNO a level of autonomy in tailoring the high level outcome from the network planning process for its own regional context. So, rather than conforming to a common framework, it allows a '*certain level of customisation for each DNO to represent their individual license area, but use a similar construct such that there is a sense of comparison* (*Interview, ENA)*. While some of the network companies have produced a new scenario that best aligned with their stakeholder preferences, others felt that an existing DFES scenario was equally able to do this and that producing another scenario may be confusing for their stakeholders.

As the NDP includes network analysis, the companies can use this to identify investment needs. This assessment activity is known as the Distribution Network Options Assessment (DNOA). The DNOA allows the networks to plan for either investment or flexibility tenders to address expected future constraints. The companies can put in place measures to address constraints that are likely to arise due to increased loads on their networks and then use an economic assessment to find the optimal outcome. Within the network companies, there are separate teams that deal with either market (commonly referred to as Distribution Service Operations (DSO)) or conventional reinforcement solutions (known as Distribution Network Operations (DNO)).

For RIIO ED2, the networks are required to take a 'flexibility first' approach (Ofgem, 2021b).[5] In 2021, as an action in the Smart System and Flexibility Plan, the distribution networks were required to '*deliver and adopt a standardised approach to procuring flexibility and managing connections across all GB distribution networks by 2023*' (BEIS and

[5] Specified in licence condition SLC31E

Ofgem, 2021, p. 85). In response, the ENA's Open Networks project,[6] developed a methodology for assessing which route – flexibility or reinforcement – would be the most cost-efficient for the customer. This was labelled the Common Evaluation Methodology (CEM) (Energy Networks Association, 2022b). The purpose of the CEM is to improve the transparency of the network companies' investment decisions, with the networks able to use an Excel file tool provided by the ENA for their calculations, the premise being that flexibility service providers can be reassured that the network companies '*are acting as neutral market facilitators when undertaking their DSO activities'* (ibid. pp.7). In the Draft Determinations Core Methodology Document, Ofgem stated that all network reinforcement decisions would be subject to the CEM Cost-Benefit Analysis to '*facilitate comparison between companies and performance tracking over time against a set of key outcomes*' and that these metrics would be used to form part of the DSO incentive (Ofgem, 2022b, pp. 92–93).

The Load Related Expenditure (LRE) plan then provides evidence for the more detailed Engineering Justification Papers (EJP). The regulator sets out a framework used to generate the EJPs (Ofgem, 2021c) as part of the overall Business Plan Guidance (Ofgem, 2021a). A successful EJP is expected to establish the need for the investment and present supporting evidence, to demonstrate a structured options development process, and detail the proposed investment scope, costs, risks, and benefits (Ofgem, 2021c pp. 4). The EJPs cover both load and non-load related expenditure (network reinforcement, improving asset health or network performance) where forecast costs exceed £2m. Networks are also encouraged to produce EJPs to enhance transparency around investment decisions that may contain novel or complex solutions. The LRE plan and EJPs are submitted alongside the companies' business plans in advance of the regulator's decision on setting revenue allowances.

To sum up, based around the 'best view' scenario each company produces a comprehensive Load Related Expenditure (LRE) plan. To justify their load-related expenditure, the networks rely on the DEFS and Network Development Planning processes to establish the needs case, and use the Common Evaluation Methodology and the Distribution Network Options Assessment process to identify low-regret pathways and compare options.

3 Scenario-based planning in the regulatory regime

The move to scenario-based planning for load growth marks an important change in the approach to regulation and capital investment, which became established in Britain following privatisation. Dealing with the uncertainty associated with net zero will likely become a more prominent feature of regulation in the years ahead, with planning for load related expenditure (LRE) playing a key role in this new regulatory framework and dynamic.

Prior to their final determinations, Ofgem discussed four possible options around how the network companies would develop their plans in line with net zero (Ofgem, 2020, p. 30): one with a central set of assumptions and a forecast upon which baseline allowances would be based; one with a central forecast but with 'uncertainty mechanisms' enabling some flexibility to account for changes; one where the plan is bespoke and developed with regional stakeholders; and one with a bespoke plan but with uncertainty mechanisms. Ofgem outlined that they saw risks with a purely decentralised approach, one issue being that the companies

[6] Workstream 1A Flexibility

would be incentivised to input inaccurate forecasts, with an overestimation of demand and then underspend, resulting in the appearance of efficiency savings and additional profits. Other issues identified were the likelihood that networks would be affected differentially by climate change and the differential speed of heating and transport electrification across regions, e.g. depending on proximity to gas mains.

For RIIO ED2, there have been improvements in the standardisation of the DFES methodologies and for the NDP process, although there is still some variation in how data is interpreted within the companies and methods used for obtaining evidence from consumer engagement, as discussed earlier. However, as the DNOs used the common DFES methodology framework (Figure 3), the regulator was able to compare and contrast the requested expenditure across the companies following a number of adjustments made to the underlying data. Using this common methodology highlighted the regional differences in each of the companies' investment plans, and, as the regulator outlined, '*we very quickly realised it was going to be quite difficult to set allowances consistently for all the DNOs given all of their different scenarios (Interview, Ofgem).* What standardising DFES and other forecasting tools has revealed is the large variations both within and across the distribution network companies. There is also some uncertainty over which pathway is likely to be followed, leading Ofgem to release revenue for a least regrets option and to introduce several uncertainty mechanisms.

In the draft determinations, two mechanisms were considered to account for the uncertainty and variability associated with what Ofgem describes as 'low value, high volume projects' (Ofgem, 2022b, p. 41). Ofgem consulted between an output-based mechanism where numbers of LCTs would be considered (£ per device connected, scheme completed, new connection) or a capacity-based mechanism (£ per MVA and/or km). The capacity mechanism was chosen as it is homogenous across the DNOs and, as they see it, involves less risk of volume manipulation. Using the scenario forecasts provided by the companies in their DFES, Ofgem created a baseline from all the separate scenarios. The rational for doing so was outlined by an interviewee from the regulator,

'*So the result of that was across the different DNOs there were fairly different assumptions which, to be honest, once you end up aggregating them all and taking away some regional variation, actually have broadly similar outlooks. I think it largely boiled down to customer transformation being the most prevalent' (Interview, Ofgem).*

To ensure a least regrets option, Ofgem then adjusted these scenario forecasts to System Transformation as a scenario baseline – the most conservative FES scenario in terms of heat pump and EV roll out – with automatic triggers '*that will enable networks to invest immediately and without administrative burden if LCT uptake exceeds this scenario'* (Ofgem, 2022d, p. 16). In total, for RIIO ED2, three volume-based uncertainty mechanisms (UMs) were introduced for load-related expenditure: low voltage services, secondary reinforcement, and an indirect scalar mechanism for costs associated with these uncertainty mechanisms being triggered (Ofgem, 2022c). Although there was a recognition of the rationale for using such a baseline and flexibility through the uncertainty mechanisms, there was some concern expressed amongst the DNOs as using these types of volume drivers may introduce a new layer of bureaucracy and potentially cause delays in releasing funds (Interviews, DNO).

In total, Ofgem awarded the electricity distribution companies a load related expenditure revenue allowance of just under £3.2bn. The annual revenue allowance is 40% higher than the previous price control but with £1.04bn of the awarded LRE as a contingency fund, accessed via the volume driver uncertainty mechanisms (Ofgem, 2022d).

The decision not to include LRE in the company baseline revenue allowances, rather to base allowances on a conservative scenario and adapt incrementally around this through the uncertainty mechanisms is a fundamental change to the price control framework and incentive regulation model. Ensuring that this approach operates seamlessly, enabling the networks to cover costs and deal with the fundamental uncertainties around net zero, will undoubtedly pose challenges for distribution network operators and the regulator in the years ahead. In informing this debate there may be insights to be gained from the broader economics literature on the timing of network investments under different regulatory incentive regimes (e.g. Borrmann and Brunekreeft, 2020).

4 Future developments

When the electricity supply industry in Britain was privatised in the 1990s, it was expected that there would be steady growth and a predictable industry business model, allowing for incremental efficiency savings. The fundamental uncertainties associated with the speed and extent of electrification of heating and transport sectors has resulted in Ofgem and the UK energy department posing fundamental questions about current governance arrangements. On the back of this, in 2023, Ofgem published a suite of consultations and reform proposals[7] all of which affect future network operation, with scenario-based network planning playing a prominent role.

As part of this reform agenda, Ofgem is proposing to introduce a Regional System Planner (RSP), although, at the time of writing, there is ambiguity over the role that the new organisation will play in the system. However, at a recent Ofgem-led workshop attended by the author, there was agreement that the central planner should play a coordinating role in the creation of regional, whole system strategic plans, and to put in place formalised structures and processes to facilitate dialogue and arbitration between local areas, regions and the DNOs. These discussions and deliberations about the future of distribution level network planning are at an initial stage, but a detailed understanding of the recent history of decentralised network planning under the RIIO-ED2 process should inform these debates. As the networks are already undertaking modelling and forecasting based on stakeholder input, and using common methodologies and frameworks, as explained in detail above, the RSP should avoid duplicating these functions and identify areas where greater standardisation of assumptions and methodologies would be most beneficial for consumers.

[7] The Future of Local Energy Institutions and Governance (Ofgem, 2023b), Future Systems and Network Regulation (FSNR) (Ofgem, 2023a), The Future of Distributed Flexibility (Ofgem, 2023c) and the Review of Market Arrangements (REMA) (DESNeZ and BEIS, 2022)

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