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Research article

Low carbon technologies and the grid: Analysing regulation and transitions in electricity networks

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ABSTRACT

This paper analyses how uncertainties around the uptake of heat pumps and electric vehicles (low carbon technologies) are being managed within the regulatory regime for electricity distribution networks in Britain. Within the sustainability transitions field several studies have identified electricity networks and regulation as an important topic and have focused on the introduction of innovation incentives for monopoly network companies. The main contribution made to this research agenda is to broaden the frame of analysis from innovation policy to examine the challenges associated with whole system reconfiguration and the transformation of incumbent regulatory regimes. The empirical basis of the paper is an analysis of regulatory decision making in relation to the approval of large capital investments in regional electricity distribution networks. We analyse attempts to reconfigure the networks and the incumbent regulatory regime, focusing on efforts to align network planning and regulation with net zero.

1. Introduction

In European countries with mature and reliable power systems, long-term planning of electricity distribution networks has not been high up on the agenda over the past number of decades. This has been because demand for electricity has been relatively stable and predictable, while the investment needs in these long-lived infrastructure assets have, in general, not been significant. In terms of decarbonisation and electricity system transitions, the policy and regulatory focus in European countries has predominantly been on decarbonising electricity generation through large scale renewables projects, whilst dealing with the associated investment and co-ordination challenges of integrating these generation assets into the high voltage transmission networks.

However, following the Paris Agreement of 2015, and subsequent commitments made by many countries since to reach net zero by mid-century, the need to decarbonise heating, cooling and transport demands has become much more of a priority. While this poses significant challenges for policy makers in accelerating the uptake of low carbon technologies (LCTs) such as EVs and heat pumps, the impact of decarbonising demand on regional and local electricity distribution networks is only now coming into focus. This is as sales of electric vehicles increase rapidly in many wealthier countries, combined with a concerted effort in Northern European states to switch from natural gas to electric heat pumps following the 2021–2023 energy crisis.

While integrating large numbers of LCTs over a short timeframe presents significant – in cases immediate – technical challenges, the long-term trend of demand-side electrification poses fundamental questions for how regional and local electricity distribution

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networks are regulated and governed. Uncertainty about the pace of LCT diffusion over the coming decades has opened up a debate about the need for a new approach to energy regulation, one which is based much more on long-term planning and investments ahead of need to meet growing demand for electricity across society. This is in tension with the established liberalised model of energy network regulation which has prioritised short-term efficiencies and cost reductions for consumers.

Although electricity network planning and regulation has typically been the domain of technical specialists and economists, the contribution of this paper is to situate these networks and their regulation in broader socio-technical terms, drawing on and developing the literature on large technical systems and sustainability transitions (Verbong and Geels, 2010; Geels, 2002; Markard, 2018). Within this field, a small number of studies have focused on electricity networks and regulation, analysing the specific challenges of innovation and transitions in highly regulated sectors, and focusing primarily on the introduction of innovation incentives for monopoly network companies (Bolton and Foxon, 2011; Bauknecht, 2012; Bauknecht et al., 2020; Lockwood, 2023; 2016). The main contribution the paper makes to this research agenda is to broaden the frame of analysis, from a focus on innovation policy to an analysis of systemic challenges associated with large scale capital investments in the incumbent networks and the reconfiguration of established regulatory regimes to deal with uncertainties around net zero transitions.

In the next section we begin by situating the paper within the literature on socio-technical systems and sustainability transitions, explaining how our study contributes to an understanding of whole system reconfiguration processes. We then outline the methodology and the sources drawn up to develop the case. This is a detailed analysis of regulatory decision making in relation to approving (or not) large capital investments in the regional distribution networks in Britain. A particular focus of the analysis is how uncertainty around the uptake of LCTs across the distribution networks is being managed within the regulatory regime. We outline how a scenario-based approach to forecasting LCT uptake, in line with the country's net zero targets, was implemented by the electricity distribution network companies in their long-term investment plans. Based on a detailed analysis of the latest regulatory review of these network plans, we identify a tension between ambitious investment planning and the established regulatory model which has been inherited from the liberalisation era. We find that although incumbent actors are realigning around a long-term system transformation agenda for the networks, there are conflicts and tensions inherent in this as the monopoly network operators may exploit uncertainties and increase their profits. Given this risk, the regulator is struggling to balance its existing priority of protecting the interests of consumers with a long-term transformational agenda. Based on the recent experience in Britain, the final sections of the paper then reflect on the overall reconfiguration process, drawing lessons for other countries with net zero commitments and liberalised electricity market models.

2. Transitions, networks and regulation

2.1. Regulation and innovation in socio-technical systems

While regulation has been a feature of electricity and other networked systems such as telecommunications and railways since their inception in the late 19th century (Chandler, 1977; Hughes, 1983), in recent decades, with the introduction of competition and liberalisation reforms, the discussion of regulation in relation to energy systems has been typically analysed through the lens of microeconomics (Kahn, 1988; Beesley and Littlechild, 1989; Joskow, 2008).

A large part of the economics literature on the subject has been concerned with the relative efficiency of different regulatory regimes, in particular rate-of-return (RoR) versus incentive-based approaches (Armstrong and Sappington, 2004; Tirole and Laffont, 1993). When they liberalised their electricity systems in the 1990s and 2000s, Britain and the EU countries have generally favoured an incentive-based regulatory model (Meeus and Glachant, 2018; Jamasb, 2020), whereby the returns that a network operator makes is linked to their performance, as opposed to being prescribed by a regulatory authority, as in RoR. The reason for this preference was that it – in theory – encouraged the operators of networks to refrain from overinvesting in their systems. With the incentive approach, the idea was that regulation would 'mimic the market' (Littlechild, 1983) and punish any regulatory monopoly which did not push down on costs and operate the existing asset base as efficiently as possible – termed 'sweating the assets' (Bolton and Foxon, 2015; Mitchell, 2008).

As the emphasis of regulation has moved on from a narrow focus on economic costs and short-term optimisation, a body of literature on innovation in networks and regulated sectors has developed within the sustainability transitions field (Bolton and Foxon, 2011; Bauknecht, 2012; Bauknecht et al., 2020; Lockwood, 2023; 2016; Frantzeskaki and Loorbach, 2010; Geels and Turnheim, 2022; Andersen, 2014). A strand of this literature has focused on incentives introduced by regulatory agencies designed to encourage monopoly network operators to adopt more innovative approaches to managing their systems. The specific character and challenges associated with fostering innovation in highly regulated regimes such as electricity distribution was outlined in Bolton and Foxon (2011). They identified as a particular challenge the co-evolution of regulatory incentives and organisational routines of network companies which has resulted in a conservative approach to innovation. As a result, even incremental innovations require protracted institutional changes and face significant barriers to their wider uptake (Lockwood, 2016).

A general finding across the literature on electricity networks, transitions and innovation is that the liberalisation reforms of the 1990s and 2000s hollowed out the R&D capacity of the sector (Jamasb and Pollitt, 2008; Markard and Truffer, 2006; Jamasb et al., 2023; Schittekatte et al., 2021). In-depth empirical research by Bauknecht et al. (2020) corroborates this. In a study of the Norwegian electricity networks, they find that 'there is a mismatch between the regulatory objective to increase the efficiency of existing network functions, on the one hand, and the need to govern the transition towards a new energy system, on the other hand' (Bauknecht et al., 2020: p. 319). According to the authors, the lack of innovation in these sectors is not only a market failure – a lack of incentives under the regulatory framework – but also due to broader institutional factors, such as the legal mandate of regulators in liberalised regimes.

They characterise this as a 'directionality failure' and advocate a reflexive governance model, whereby regulators are given scope to experiment with new methods and incentives.

2.2. Technology acceleration and system reconfiguration

Through this socio-technical systems lens, long-term network planning and regulation is not viewed as a narrow economic or optimisation problem, rather it involves the reconfiguration of an incumbent regime composed of interacting technical and non-technical elements, including politics, company strategies and end-users (Stenzel and Frenzel, 2008; Bolton and Hannon, 2016; Bauknecht et al., 2020; Valenzuela and Rhys, 2022). Such a socio-technical systems approach can open-up the analysis of electricity network planning, investment appraisal and regulation, providing insights into the challenges associated with adapting and reforming the established approach to governing electricity networks and other large technical systems.

However, the existing research on networks and their regulation in the transitions field has focused primarily on innovation schemes, regulatory experiments and R&D projects, rather than the core functions of regulators. In particular, the operation of regulatory regimes as a means of delivering large scale capital investment programmes in the networks has been largely ignored. Given recent developments in energy and climate policy, in particular commitments to reach net zero by mid-century, there is a clear need to reposition studies of networks, regulation, and transitions in the context of deep and accelerated structural changes to energy systems.

As has been outlined elsewhere in the literature on transitions and technology acceleration (Roberts and Geels, 2019; Hyysalo et al., 2018; Winskel et al., 2014; Roberts et al., 2018), rather than the emphasis being on experimentation and early stage technological innovations, the focus of transitions studies needs to shift towards the rapid deployment of clean technologies at scale and the reconfiguration of incumbent regimes and systems. In this context, attention moves from innovation and nurturing niches to the dynamics of whole system change (Geels and Turnheim, 2022), technological decline, phase out (Turnheim, 2023) and the reconfiguration of mature systems (McMeekin et al., 2019).

Alongside disruptive and emergent process therefore, the analysis of long-term system transitions should also consider how incumbent regimes are adapted and adjusted to a changing external environment. Whole system reconfiguration therefore broadens the conceptual lens to the entire system, or chain of production, networks and consumption; as Geels et al. note, 'uneven and fragmented analysis of electricity may be problematic because the electricity system does form one large, integrated socio-technical system' (McMeekin et al., 2019: p. 1217).

2.3. Network regulation and net zero

The combination of accelerated change in electricity generation – primarily wind and solar deployment – and the demand side of systems as heating and transport are increasingly electrified, will require a fundamental rethink of the configuration of electricity networks and their regulation. Across a net zero timeframe – out to 2050 – network planning and investment appraisal is faced with fundamental uncertainties, such as the speed of uptake of electric vehicles and heat pumps, the nature and consistency of policy support for net zero, and future technological changes which may reduce or increase demand for electricity in particular geographic locations. Tensions and misalignments between the pace of change in different parts of the system is already creating bottlenecks and barriers to the further integration of low carbon technologies, what historians of large technical systems refer to as 'reverse salients' (Hughes, 1987; Lovell, 2015). This includes, for example, long connection queues for access to networks, rising congestion management costs due to the inability of transmission systems to absorb renewable output, and questions about the ability of local and regional distribution networks to adjust to rapidly changing demand patterns. In negotiating these challenges, regulators sit as crucial intermediaries in system transitions as they play a key role in aligning the development of incumbent network systems with emerging innovations such as wind, solar, storage and LCTs. Therefore, a deeper analysis of their role in socio-technical systems can enhance our understanding of incumbent regimes and reconfiguration processes.

Recent literature on energy regulation has highlighted the challenges of reconfiguring established regulatory regimes given the fundamental of uncertainties around long-term system transitions (Duma et al., 2024; Joskow, 2024). The traditional role and remit of regulators had been to protect the interests of consumers by pushing down on costs and generally taking a cautious approach to approving new capital investments (Geels and Turnheim, 2022; Bolton, 2011; Bolton and Foxon, 2011). However, there is now a recognition that, while this regulatory model may have delivered lower costs to consumers in the past, the system has reached a tipping point whereby the benefits to consumer from traditional regulation are diminishing (BEIS and Ofgem, 2022; NIC, 2019).

Regulators now face a dilemma. Strategically planning the networks and approving investments ahead of need presents risks as, given the fundamental uncertainty about the pace and extent of heating and transport electrification, consumers could be exposed to stranded asset risks and unnecessarily high network tariffs. However, while a cautious approach to approving grid expansion may have been appropriate in an era of static – or even declining – demand for electricity, in the coming years and decades it could lead to a situation where there is a mismatch in the timescales of LCT diffusion and network capacity expansion, resulting in grid bottlenecks and perpetuating fossil fuel lock-in.

The empirical analysis in this paper provides insights into the processes through which regulators are seeking to align the development of incumbent network systems with net zero transitions, thus enhancing our understanding of incumbent regimes and reconfiguration processes in transitions. As outlined in the subsequent sections of the paper, decision making about capital investments and network costs is an iterative process, whereby regulators formally scrutinise and appraise investment plans which are submitted by network operators. This interaction between network operators and the regulator is a highly structured and formalised one, and can thus be analysed as a stepwise reconfiguration of the incumbent regime. Given that the distribution network operators in Britain – and elsewhere – are now required to plan their systems to accommodate 2050 net zero targets, we pay particular attention in the empirical analysis to the use of long-term scenarios as a means of identifying critical network investments required to integrate LCTs and to manage uncertainties in transition pathways. As discussed further in Section 5 of the paper, the use of scenarios at the interface of network planning and regulation is a particularly novel feature of the British case which may provide valuable lessons for countries with similar regulatory regimes and decarbonisation commitments.

3. Methodology

To address the question of how incumbent regulatory regimes are being reconfigured to deal with net zero, we construct a detailed case history of the recent price control review for electricity distribution networks in Britain. In this we pay particular attention to how uncertainty around LCT uptake was handled by the network companies in their long-term plans and by the regulator in their appraisal of investments and costs.

A case study approach was deemed appropriate to analyse how uncertainties associated with LCTs and net zero are interacting with the established regulatory regime for electricity networks. As outlined elsewhere (Yin, 1994; Flyvbjerg, 2006; George and Bennett, 2005), case studies are an established means of uncovering complex and highly contextualised processes of change. They are a useful aid to uncover patterns and processes, enabling causal mechanisms which influence outcomes to be uncovered and subsequently analysed (Mayntz, 2004), thus helping to develop and refine theoretical frameworks.

While there are advantages to case study research, the limitations should also be recognised (Flyvbjerg, 2006), a particular issue being that highly context-dependent and situated studies are less amenable to broader generalisation. A means of overcoming this is through a comparative case study approach which involves selecting multiple case studies and comparing them for the purposes of generalisation. However, as with any methodological choice there are trade-offs to be made. An alternative to such an instrumental approach to case studies is an intrinsic design which involves single and in-depth case analysis. We opted for this approach as knowledge is generated on the particularities of the case, which can subsequently be drawn on for more structured case comparison or the identification of variables.

The electricity distribution network sector in Britain was chosen as a suitable case to investigate the changing role of regulation in the context of net zero transitions for several reasons:

Firstly, the British approach to regulating electricity networks and other utilities has been influential internationally. The country was one of the first to liberalise its electricity system in the early 1990s and to introduce incentive regulation for its transmission and distribution networks (Bolton, 2021). The framework was originally based on the RPI-X model which involved a minimal level of regulatory intervention, but from the 2010s the RIIO approach has been implemented. As explained in Section 4, this puts a greater emphasis on outputs and long-term investment, and has been cited as an influence on European (Rious and Rossetto, 2018) and US (Joskow, 2024) regulators, therefore its development and adaptation has wider significance.

The second reason why the British case was chosen was the commitment to net zero and the uncertainty around LCT diffusion. The UK was the first country to legislate for net zero following an amendment to its 2008 Climate Change Act passed in June 2019. Following this, in December 2020, the Climate Change Committee (CCC) published its advice on the 6th Carbon budget, covering the crucial 2033–37 period (Climate Change Committee, 2020). The CCC's analysis outlined that, as the main source of emissions

Table 1
List of key regulatory documents analysed.

December 2019	RIIO-ED2 Framework Decision[1] and working groups[2]
July 2020	RIIO-ED2 Sector Specific Methodology Consultation[3]
December 2020	RIIO-ED2 Sector Specific Methodology Decision[4]
August 2020	RIIO-ED2 Draft Business Plan Guidance
September 2021	RIIO-ED2 Business Plan Guidance[5]
December 2021	Six DNO business plans and relevant annexes[6]
February 2022	RIIO-2 Challenge Group Independent Report on Electricity Distribution Business Plans[7]
June 2022	Ofgem's RIIO-ED2 Draft Determinations[8]
November 2022	Ofgem's RIIO-ED2 Final Determinations (main document and appendixes)[9]

[1] https://www.ofgem.gov.uk/publications/riio-ed2-framework-decision.
[2] https://www.ofgem.gov.uk/publications/riio-ed2-working-groups.
[3] https://www.ofgem.gov.uk/publications/riio-ed2-sector-specific-methodology-consultation.
[4] https://www.ofgem.gov.uk/publications/riio-ed2-sector-specific-methodology-decision.
[5] https://www.ofgem.gov.uk/publications/riio-ed2-business-plan-guidance.
[6] SP Energy Networks: https://www.spenergynetworks.co.uk/pages/our_riio_ed2_business_plan.aspx National Grid Electricity Distribution: https://yourpowerfuture.nationalgrid.co.uk/riioed2-business-plan UK Power Networks: https://ed2.ukpowernetworks.co.uk SSE Networks: https://ssenfuture.co.uk/wp-content/uploads/2021/12/24645-SSEN-ED2-Final-Business-Plan-Website.pdf Electricity North West Limited: https://www.enwl.co.uk/about-us/regulatory-information/our-business-plan-2023-2028/businessplan2023-2028/ Northern Power Grid: https://ed2plan.northernpowergrid.com.
[7] https://www.ofgem.gov.uk/publications/riio-2-challenge-group-independent-report-ofgem-electricity-distribution-business-plans.
[8] https://www.ofgem.gov.uk/publications/riio-ed2-draft-determinations.
[9] https://www.ofgem.gov.uk/publications/riio-ed2-final-determinations.

reductions to date in the UK has been the phase out of coal-fired electricity generation – a process now completed – hitherto neglected sectors such as heating and transport will need more policy attention.

A third and final reason for choosing Britain was the innovative use of net zero scenarios to forecast the future uptake of LCTs and input into network planning and regulation. Since 2011 the Future Energy Scenarios (FESs) have been published annually by the Electricity System Operator (NGESO), the body responsible for operating and planning the electricity transmission system. The FESs play an increasingly important role in the development of business plans and investment appraisal of major projects. As will be discussed in more detail below, the use of these scenarios as forecasting tools for LCTs played a significant role in the electricity distribution network plans and the regulator's appraisal.

The case analysis of electricity distribution network planning and regulation in Britain covers the 2019 to 2023 period when the regular conducted a review of network investment needs and costs as part of its price control review process. The empirical analysis is primarily based on the key consultation and decision documents which were published in advance of the regulator's 'final determination' in November 2022. We also analysed the six business plans submitted by the distribution network operators (DNOs) in advance of this decision and material published by technical working groups which fed into the regulator's analysis and decisions. The main documents analysed are listed in Table 1 below.

Using these documents, we constructed a high-level case history of the price control, building an understanding of this as a system level reconfiguration process where the regulator and incumbent network operators interact to shape the regulatory regime. Following this we reanalysed the documents to identify more specifically the issues raised by LCTs and how key uncertainties were dealt with by the regulator in its appraisal of company business plans. To test the accuracy of our document analysis and to elicit a range of views, we also conducted 17 semi-structured interviews with representatives of the network companies and the regulator, along with several independent experts. We interviewed representatives of all six electricity DNOs (6), a representative of their industry body (1), regulatory officials (3), a consultant hired to conduct LCT forecasting by two of the DNOs (1), the national electricity system operator (3), and NGOs representing consumers (3). These interviews lasted for one hour approx., and in them we discussed the planning and regulatory process from their individual and organisational perspectives, enabling us to triangulate with different sources of evidence from companies, the regulator, and other stakeholders. The interviews took place between December 2022 and late April 2023. This enabled the interviewees to reflect on the entire price control process which commenced in late 2019 and concluded in late 2022, following the publication of the regulator's final determination (see Table 1 below).

In analysing this material, three main aspects of the price control process came to the fore and were used to structure the case study: Firstly, how the DNOs integrated LCT forecasting into their business plans using the FES net zero scenario framework (Section 4.2). Secondly, how the regulator evaluated these LCT forecasts and the resulting cost submissions in the company business plans (Section 4.3). Finally, emerging conflicts between the regulator and the DNOs, highlighting how net zero scenarios and LCT forecasts became a

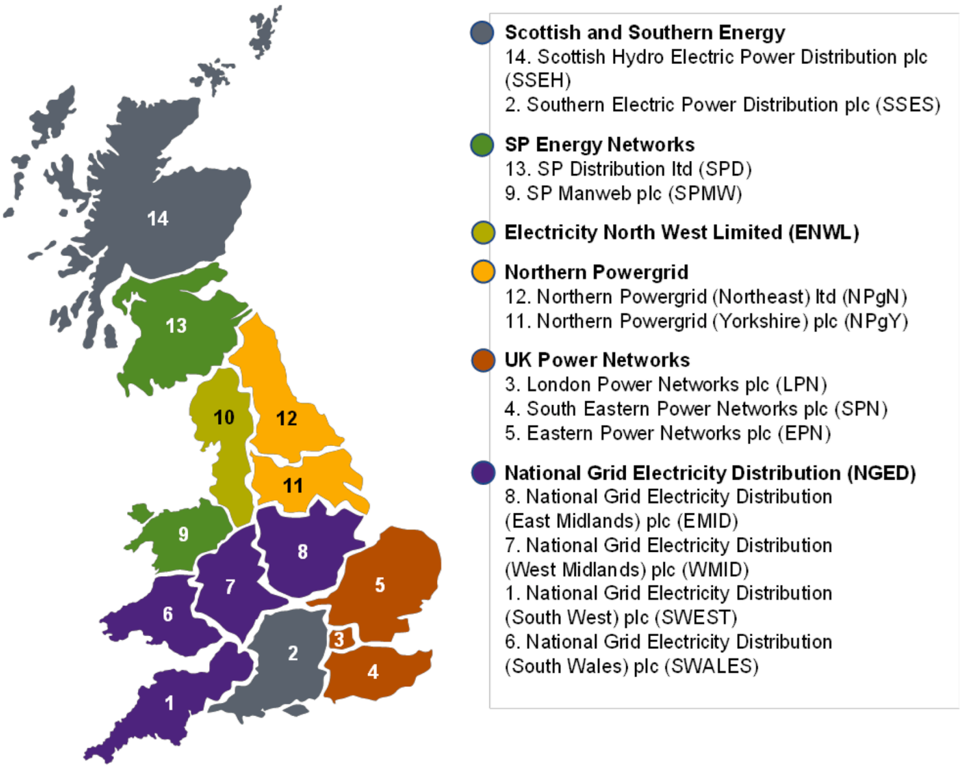

Fig. 1. Map of electricity distribution networks in Britain (Ofgem).

contentious aspect of energy regulation (Section 4.4). Before outlining these detailed sections, Section 4.1 provides a brief introduction to the regulatory regime for electricity distribution networks in Britain.

4. Case study of LCTs and network regulation in Britain

4.1. Background to the electricity networks and regulation

Britain's electricity distribution networks are organised around fourteen regions and operated by six private distribution network operators, or DNOs (see Fig. 1). The DNOs hold licenses to own and operate the networks and, as natural monopolies, their businesses are regulated through multi-annual price control reviews. These reviews are conducted by an independent regulatory agency (the Office for Gas and Electricity Markets (Ofgem)) whose principal duty is to protect the interests of consumers, as originally set out in the 1989 Electricity Act. Ofgem does this whilst having regard to the financial stability of the sector, security and diversity of supply, the interests of vulnerable customers, and the efficient use of energy.

As an economic regulator, Ofgem determines the revenues that the regulated companies can collect from their customers through network charges. Under this regime Ofgem caps their revenues in advance and incentivises them to operate their businesses efficiently, whilst delivering value to customers throughout the price control period. Setting consumer-focused objectives and adjusting allowed revenue is an iterative process which takes place every five or eight years. In adjusting revenues and prices, the regulator must balance the interests of companies and their investors with those of the electricity consumer.

This is a very high-level sketch of a much more complex and multifaceted regulatory regime for the energy networks in Britain which is known as RIIO – RIIO standing for 'Revenue = Incentives + Innovation + Outputs'. RIIO has been in place for the electricity distribution networks since 2015, with a new price control period – RIIO-ED2 – commencing in April 2023 and running for five years.

Under the RIIO framework operational and capital expenditures are combined into total expenditure – totex for short. Based on data contained in the business plans submitted by the DNOs, the regulator deploys statistical benchmarking across the sector to calculate totex at the start of each price control period. This modelled totex is then combined with a bottom-up analysis of individual cost items – 46 in total – to determine 'allowed revenue'. This is what the regulator deems to be appropriate to cover a DNO's costs for delivering prescribed outputs, operating its business efficiently and investing in its asset base over the price control period.

4.2. LCT forecasting in the DNO business plans

As part of each price control review, Ofgem provides formal guidance to the DNOs in advance of them developing and submitting their final business plans. A novel feature of the RIIO-ED2 price control was that the companies were required to think long-term about the development of their networks, with the DNOs incorporating net zero aligned – 2050 – scenarios into their business plans for the first time. As one DNO interviewee characterised it, this required a change 'from historical based to scenario based' forecasting for load growth across the networks, which was a fundamental shift in philosophy and methodology (Interview, DNO 1).

Forecasts for LCT uptake by consumers were required to be based on a common scenario framework known as the Future Energy Scenarios (FESs). The FESs are based on different assumptions around technological change and the degree to which society and consumers will be drivers of the net zero transition (see explanatory Box 1). Based on this scenario framework, Figs. 2 and 3 provide an illustration of the uptake of LCTs across these scenarios, highlighting the different diffusion patterns of EVs and heat pumps which are used by electricity network companies as key inputs into their models and long-term investment plans.

Given that the FES framework has been developed by National Grid for the main purpose of planning the transmission networks, Ofgem decided to allow each regional DNO a measure of autonomy in developing their own net zero scenarios, which became known as Distribution Future Energy Scenarios (DFES). A key purpose of each company's DFES would be to forecast LCT diffusion – both heat pumps and electric vehicles – across their respective regions. Although the prospect of requiring the companies to plan their systems according to a single or common scenario was discussed early in the review process, given the regional variations across Britain, it was decided that each DNO develop a business plan around its own a chosen core scenario – its *Best View*. This would require the companies to gather on-the-ground intelligence and consult with their stakeholders.

An interviewee from a consultancy firm who worked with several of the DNOs in developing their forecasts, and had previously fed into the early Ofgem working groups, explained the rationale behind this:

> the idea was that you could then feed in local knowledge, better knowledge, because the problem with the National Grid Scenarios for us is that they have some national assumptions that then get distributed to our area, but we know our area better and so we have to redistribute what they give us (Interview, consultant)

In their guidance document, Ofgem provided the companies with national level forecasts and key parameters, and then instructed them to disaggregate these figures for their respective regions. The companies were required to justify choices around their *Best View* scenario for 2030, incorporating these parameters into their load related expenditure submissions, as Ofgem summarised in their business plan guidance:

> DNOs will need to clearly explain the anticipated uptake rates of LCTs, in particular EVs and heat pumps. Where these assumptions vary on a locational basis, i.e. EV clustering, this should be explained. Assumed profiles for dominant types of EV charging, heat pump consumption and export from embedded generation shall be detailed where material in the calculation of

Box 1
Overview of the FES 2050 scenario framework (National Grid, 2023).

Box: Overview of the FES 2050 scenario framework (National Grid ESO, 2023)

	Slow speed of decarbonisation	***Fast speed of decarbonisation***
High level of societal change	*Consumer Transformation (1)*	*Leading the Way (2)*
Low level of societal change	*Falling Short (3)*	*System Transformation (4)*

Figure: Illustration of the Future Energy Scenarios. Based on NGESO FES 2023 Report.[10]

1. *Consumer Transformation* involves a highly engaged demand side and a high level of electrified heating
2. *Leading the Way* involves a rapid decarbonisation – net zero by 2046 – which high levels of investment in a diversified suite of low carbon options
3. *Falling Short* involves low take up of LCTs and a slow pace of decarbonisation. Net zero is not reached by 2050
4. *System Transformation* involves more centralised solutions and widescale use of hydrogen for heating, rather than heat pumps

https://www.nationalgrideso.com/future-energy/future-energy-scenarios-fes

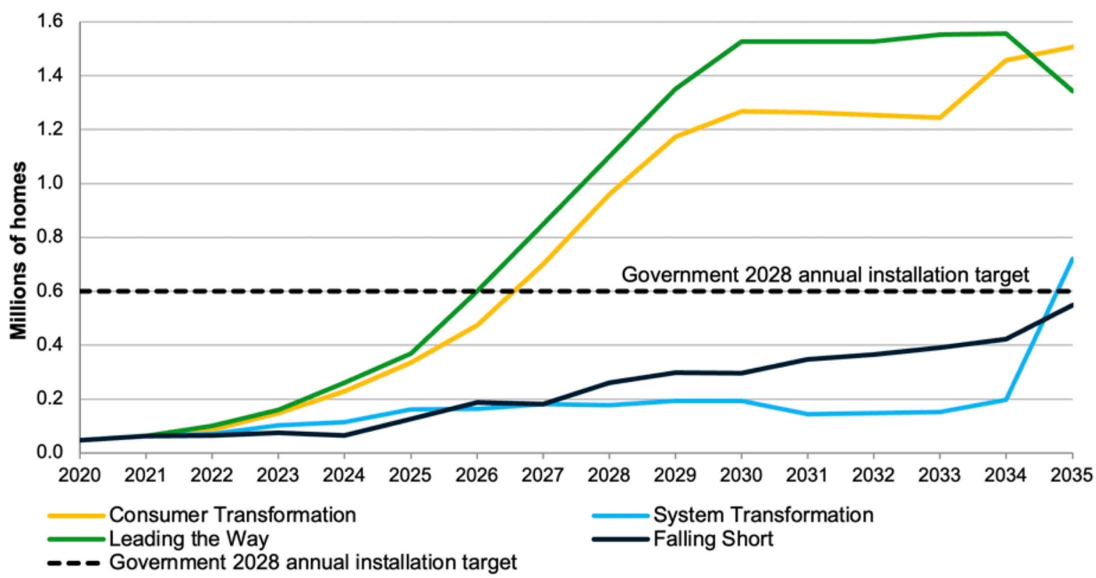

Fig. 2. Heat pumps deployment to 2035 across the FESs (FES 2023 workbook, EC.08).

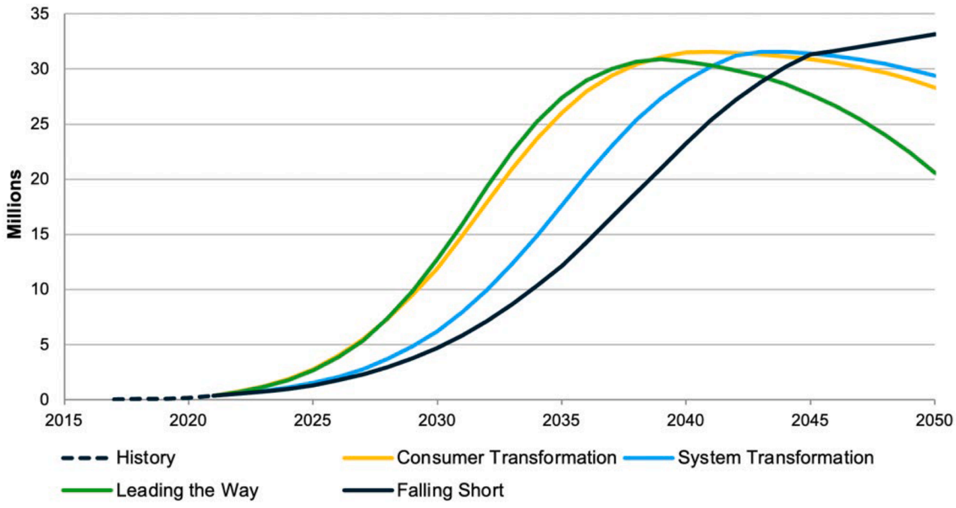

Fig. 3. Electric Vehicle deployment to 2050 across the FESs (FES 2023 workbook, EC.11).

> peak true demand, along with descriptions of how future changes in these profiles have been factored into forecasts (Ofgem, 2021: p.92)

Ofgem also required that deviations from these national projections be based on bottom-up criteria, in particular evidence which incorporated an understanding of local context and stakeholder views:

> Stakeholder engagement and DFES inputs should be described, especially where they have a significant influence on the need to invest in network capacity. The circumstances for when regional strategic developments are taken into consideration should be detailed, explaining what evidence is sought to identify the level of certainty (ibid.)

The companies were required to meet minimum standards in terms of how their forecasts were consistent with both the 2020 version Future Energy Scenarios *and* the Climate Change Committee's 6th Carbon Budget scenarios. If they did not meet these requirements, they would be fined 0.5 % of their revenues allowed under the price control.

Ofgem encouraged the DNOs to work towards a more standardised approach to developing their own DFESs. This work was co-ordinated by the Electricity Networks Association (ENA) – the industry body for the network operators – resulting in a 'common methodology' (Energy Networks Association, 2020) which took the forecast assumptions, then added stages through which each DNO could 'regionalise' the aggregated national data (Interview, industry body).

The decision to allow companies choose their own *Best View* core scenario around which to base their business plans was due to a concern that a common sector-wide scenario would be insufficient to capture the range of regional-specific factors driving LCT uptake, in particular the development of Local Area Energy Plans in some cities (Collins and Walker, 2023). With a more decentralised planning approach the regulator wanted to provide scope for the companies to explore uncertainties around regional-specific variations in climate ambitions and investment requirements.

This scenario planning process then resulted in a set of forecasts across the six business plans, the LCT components of which are illustrated in the figures below for the 2030 timeframe. Figs. 4 and 5 show LCT forecasts in each DNO business plan, indicating their choice of *Best View* (BV). Fig. 6 then shows the LCT forecast in each DNO *Best View* scenario adjusted for numbers of customers in their respective regions. This is in order to get an accurate picture of the levels of ambition across DNO forecast for heat pumps and EVs.

As can be seen in Figs. 4 and 5, the approaches taken by the DNOs differed with respect to their forecast ranges and choice of *Best View* within those ranges. To illustrate, one company chose its *Best View* primarily based on stakeholder feedback. In this case they felt that the *Consumer Transformation* scenario aligned with stakeholder expectations and, as part of the existing FES framework, was easily understandable.

> We took the view of the Consumer Transformation, so the CT [scenario], we use that as our best view scenario. There was some discussions internally for us to potentially go with what other DNOs have done, which is create their own scenarios. Now my view is always this is already really complex when you start to look at different years, different scenarios, different substations … why would we start to create our own one that deviates away from that, if a lot of our stakeholders are now saying that they're happy with that (Interview, DNO 1)

A second DNO cited local factors which, in their view, were slowing down the roll out of LCTs across their region, prompting them to choose a conservative core scenario upon which to base their load forecasts. In this case their choice of *Best View* was more informed by their observations of historic and medium-term trends across their region, but they also took the views of stakeholders into account.

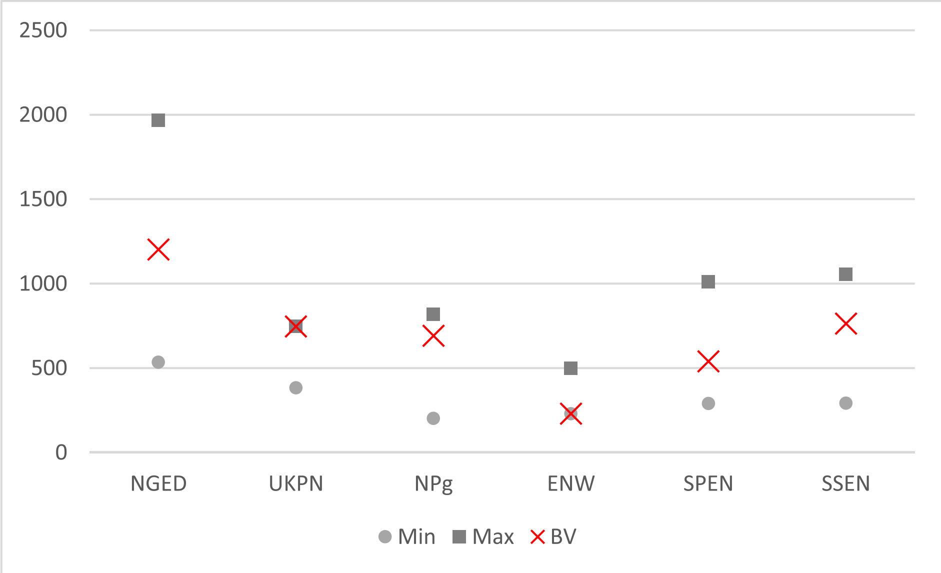

Fig. 4. Heat pump forecasts (in thousands) for 2030. Data from DNO RIIO-ED2 business plans.

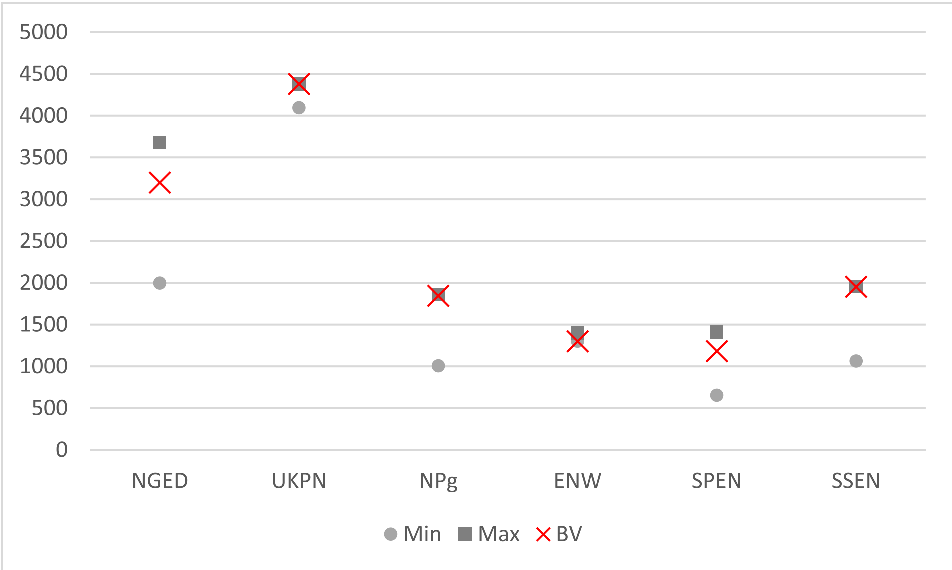

Fig. 5. Electric vehicle forecasts (in thousands) for 2030. Data from DNO RIIO-ED2 business plans.

> So the best view process we go through is, yeah, we've these scenarios that give us the envelope but using a lot more stakeholder engagement, what do we think is most likely to occur in the next nought to 10 years is where we're really focused because it's using a lot more intelligence on what's actually being observed as new connections, to a certain extent this year more so than in previous years, trying to inform some of the uptake curves of LCT's which are quite a lot lower than we find ourselves, at the bottom of our envelope of what we said in the past. The cost of living crisis, COVID, things like that have meant that the uptake of LCT's is lower than it has been forecasted for the last few years (Interview, DNO 2)

A third DNO chose a conservative *Best View* which, they argued, provided them with a realistic baseline around which to plan their investments and business operations. In the event that LCT uptake turned out to be following one of the more ambitious scenarios, additional revenues to cover investment needs could be released by the regulator within the price control period, through the use of 'uncertainty mechanisms'. As we will discuss further below, this interpretation of the role of the *Best View* – as a minimum baseline – was closest to that of the regulator's.

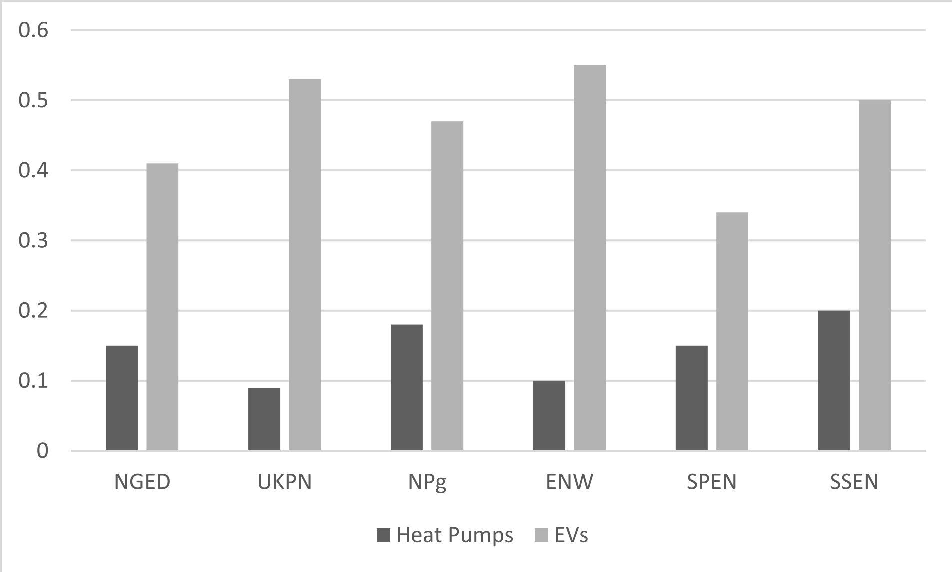

Fig. 6. LCT uptake per customer in company forecasts. DNO RIIO-ED2 business plans. Data from DNO RIIO-ED2 business plans.

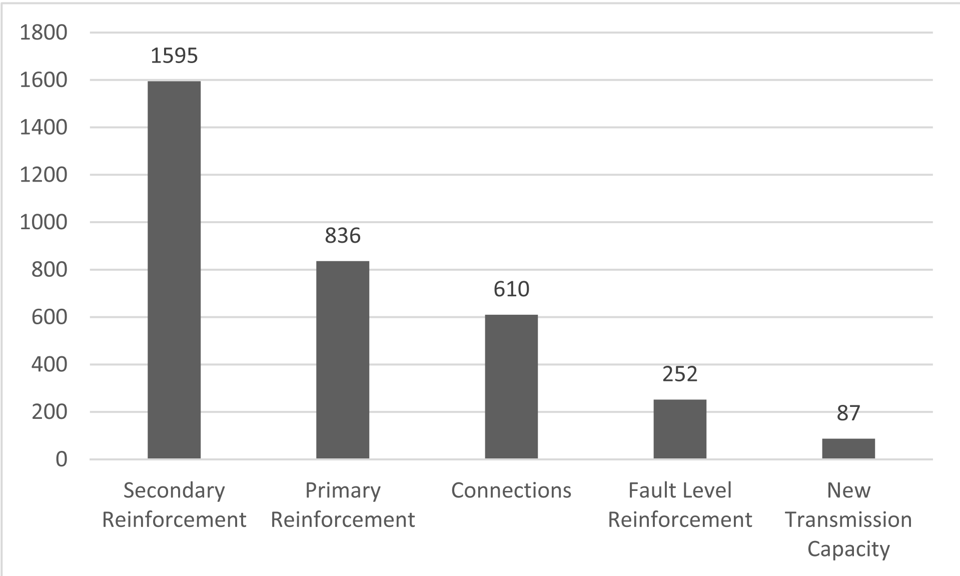

Fig. 7. Submitted cost of load related expenditure across the DNO sector (£m, 2020/21 prices). Data from (Ofgem, 2022a: Tables 21–25).

> It was more picked because it was the lowest growth and therefore the lowest cost, because our strategy was we've got the uncertainty mechanisms in place, so we don't need to unnecessarily ask for money because that's just unnecessary customer bills (Interview, DNO 3)

Underpinned by the DFES approach and the *Best View* scenarios, the figure below (Fig. 7) shows the aggregated costings submitted by the DNOs in their business plans for the main categories of load related expenditure relevant to integrating EVs and heat pumps.[1] As the figure shows, secondary reinforcement is the main category of load related expenditure, and the one which is most sensitive to assumptions about LCT uptake.

[1] *Primary Reinforcement* involves upgrading the higher voltage distribution networks; *Secondary Reinforcement* involves upgrading the lower voltage local networks; *Fault Level Reinforcement* involves spending to maintain network stability; *Transmission Capacity Charges* are costs imposed on transmission companies associated with increasing capacity at transmission-distribution connection points.

4.3. How the regulator evaluated the DNO forecasts

Arising from concerns about the significant variation in region-specific forecasts, the company estimates for LCTs summarised above were not taken as the basis upon which the regulator made its decision about allowed revenues. Rather, upon receiving the final business plans with the submitted costs in December 2021, the regulator adjusted each DNO's LCT forecasts and associated load related expenditure estimates. In conducting these 'normalisations and adjustments' the regulator was particularly concerned to develop a consistent view of the relationship between LCT additions and secondary reinforcement costs across the sector.

To achieve this, they looked across the submitted business plans and applied both 'cost adjustments' – adjustments made to unit costs – and 'workload adjustments' – standardising volumes of work required to integrate LCTs. This was based on an industry median ratio of secondary reinforcements, incorporating additional transformers, circuits, and LV services required for each DNO's core LCT forecasts (Ofgem, 2022a: see pages 257–264). Ofgem then applied this industry ratio of LCT additions to *System Transformation*, the most conservative net zero scenario in terms of LCT uptake (see Figs. 2 and 3). The resulting modelled costs and a comparison with the submitted costs for secondary reinforcement in the DNO business plans are presented in Fig. 8.

The above 'normalisation and adjustments' were made in the specific model for secondary reinforcements. When considering the implications of the different net zero scenarios, secondary reinforcement costs were a key consideration as these relate to investments at the very local, street-by-street, level of the networks and are primarily affected by LCT uptake.

The regulator also made scenario-based adjustments in its totex models through which the DNOs' submissions are compared and analysed using statistical benchmarking techniques. Here, to make this 'top down' analysis of aggregate costs consistent with the adjusted secondary reinforcement costs described above, a post-modelling adjustment was made in order calibrate the price control with the *System Transformation* scenario, in effect applying a reduction in LCT volumes across the sector. The effect of this on costs is illustrated in Fig. 9 below. This Demand Driven Adjustment came out of an overarching concern that LCT related costs were, in Ofgem's words, 'justified, efficient and represented consumer best-value' (Ofgem, 2023: p.25).

This recalibration by Ofgem resulted in the reduction of LCT volumes across the board, aligning the sector with the *System Transformation* scenario – the least ambitious of the net zero scenarios. During the price control review process therefore, a tension emerged between the usefulness of bespoke and region-specific scenarios, and the more conservative sector-wide approach that the regulator took in evaluating the business plans.

Several interviewees from the DNOs and their representatives expressed frustration at this approach, as they had been under the impression that the DFESs were in place to reflect regional differences. The following quote from a member of an industry body illustrates this view:

> …because if you try to enforce a sense of commonality, it loses the benefit of making it bespoke … we were very strong in articulating to Ofgem that there cannot be a common scenario that everybody uses, if that makes sense (Interview, industry body)

An interviewee from a DNO highlighted the complexity of the process whereby DNO forecasts were adjusted, resulting in the company being awarded a lower revenue allowance.

> That got pretty messy, if I'm honest, when it came down to Ofgem trying to understand that and then for them to benchmark us as well … So all the DNOs were sort of pinned back to the System Transformation [scenario], which didn't leave any headroom for strategic investment. And in my opinion certainly, because we were in between there and we had our investment for system transformation and a little bit more to get us to a few years into the Consumer Transformation, but they then sort of took that out. So that's part of the reason why we didn't get what we asked for, for load related expenditure (Interview, DNO 1)

At the root of Ofgem's approach was its interpretation of its main duty as an economic regulator – to protect existing and future consumers – in a way which led it to construct the price control review around a conservative view of LCT uptake. 'This', they argued, 'would ensure that RIIO-ED2 would not obstruct net-zero, while at the same time protecting consumers from high ex ante fixed allowances if LCT uptake did not materialise' (Ofgem, 2023: p.30). As the regulator further outlined:

> It is in consumers' interests to maintain lower, more conservative, ex ante allowance that flexes up, rather than having to flex allowances down for large sections of the sector (Ofgem, 2022a: p. 339)

> We opted for this scenario because, while it facilitates the delivery of net zero, it has lower LCT uptake relative to the other FES – and we consider LCT uptake to be the main external driver of DNOs' planning scenarios. This is not to say we consider System Transformation is the most likely view of the future, but instead we consider it more appropriate to use a more conservative view of LCT uptake to set allowances in order to protect consumers from higher costs than necessary while ensuring allowances are sufficient to enable net zero (Ofgem, 2022a: p. 341)

The rationale for choosing this *System Transformation* – not the companies' *Best View* scenarios – was that it would provide a consistent baseline across the sector, with additional spending on load related expenditure above this only released by the regulator within the price control period if LCT demand met certain thresholds, as outlined in a new 'uncertainty mechanism' framework. For load related expenditure, additional revenues above the *System Transformation* baseline can be awarded annually, only on the basis of meeting predefined thresholds for LCT uptake in a region, termed a 'volume driver'.

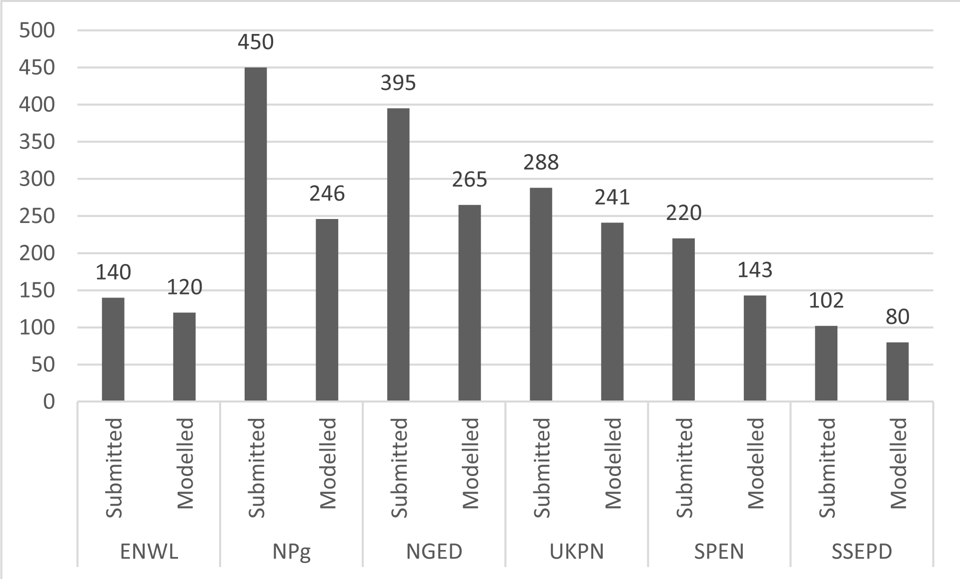

Fig. 8. Differences between submitted and modelled costs for secondary reinforcement (£m, 2020/21 prices). Data from (Ofgem, 2022a: Tables 21–25).

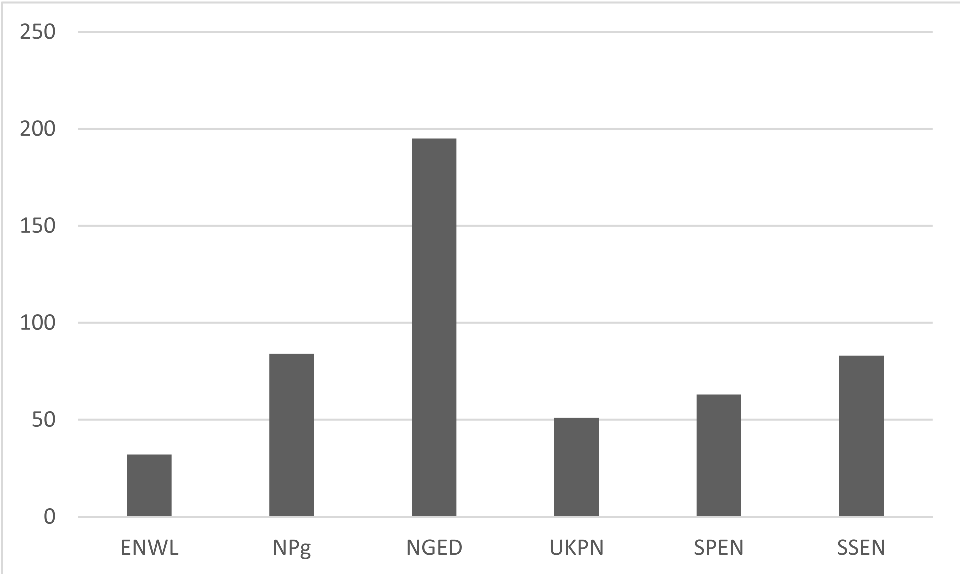

Fig. 9. Reduction in modelled costs following Ofgem's Demand Driven Adjustment (£m, 2020/21 prices). Data from (Ofgem, 2022a: Table 15).

4.4. Conflicting perspectives on net zero scenarios and LCT integration costs

The outcome of the price control announced in December 2022 was an approval of £22.2bn of allowed revenues over the five years from April 2023 to 2028 (Ofgem, 2022b). Combining the adjustments made specifically to the secondary reinforcement model and the Demand Driven Adjustment, £3.2bn of this was allocated for load related expenditure, primarily to deal with increasing LCT volumes. Despite the expectation that LCTs uptake would accelerate significantly in the coming years, the price control resulted in a real terms reduction of 17 % in baseline funding across the sector compared with the previous price control period. Fig. 10 illustrates how the £22.2bn was split across the DNOs, comparing this against their business plan submissions.

An implication of the approach taken by Ofgem was that these costs awarded to the companies were split between those which are guaranteed (non-variant costs) and those which are subjected to 'uncertainty mechanisms' (variant costs). Given the uncertainty involved, costs associated with LCTs – the load related expenditure – was designated as a variant cost, and as such made contingent on uncertainty mechanisms being triggered. The justification behind this approach taken by the regulator was that it would protect

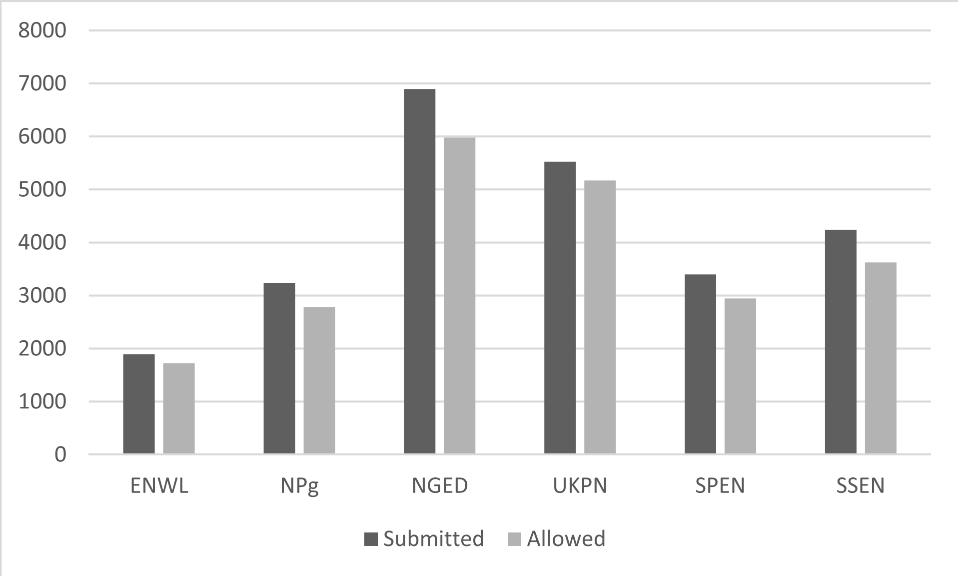

Fig. 10. Comparison of submitted costs and allowed revenues for each DNO (£m, 2020/21 prices), Data from (Ofgem, 2022a: Table 12).

consumers against unnecessarily high tariffs, if the roll out of LCTs over 2023–2028 turns out to be more in line with *System Transformation* than the more ambitious *Consumer Transformation* or *Leading the Way*.

Given the conflicting priorities in this decision – of protecting consumers against unnecessarily high prices and ensuring that the companies can finance the required investments and accommodate future LCT uptake – the regulator decided to weigh equally in its decision of how much revenue to allocate to variant and non-variant cost categories its own conservative modelled costs and the more ambitious costs submitted by DNOs in their original business plans. This was termed a 'blended approach' (Ofgem, 2023).

Ofgem's decision was however challenged by Northern Powergrid, a DNO in the Northeast region of England, who took an appeal to the Competition and Markets Authority (CMA) – the independent body who adjudicates on disputes between the regulator and the companies.[2] The issue with Ofgem's blended approach, from the company's perspective, was that, because the company's ambitious scenario was factored into the allocation decision, too great a proportion of its revenues were allocated to variant categories and, as a result, its non-variant (fixed) costs may not be covered. It could lead to a situation where a company operating efficiently, but with an ambitious net zero scenario, could be left underfunded.

In its response to the appeal, Ofgem argued that its use of the *System Transformation* scenario in calculating the total revenue allowance did not imply that the company business plans were irrelevant to the price control. As there was no prior agreed methodology for allocating revenues across variant and non-variant categories, it was reasonable, in Ofgem's view, that they use their expert judgement as a regulator in making these allocation decisions.

In September 2023 the CMA published its final determination and, on the question of how to allocate revenues across the variant and non-variant categories, it upheld Northern Powergrid's appeal of the price control (CMA, 2023). The main basis for this decision was that, as Ofgem had earlier criticised the company's submitted load related expenditure as overambitious and inefficient, it should not then have used these estimates as a key input for the allocation methodology. The difference between the DNO's submitted load related expenditure and that modelled by the regulator was of such a degree that the regulator should have decided on an alternative methodology.

Following the CMA decision, the regulator has been forced to adjust its methodology for allocating costs for Northern Powergrid (Ofgem, 2024). Rather than taking the company's submitted cost shares, it will adjust downwards the submitted load related expenditure, in line with its Demand Driven Adjustment. This will result in more overall revenues being allocated to non-variant costs categories relative to the original methodology, thus providing more guaranteed revenue and financial certainty to the DNO.

5. Discussion: the potential and limits of reconfiguration

In this section we analyse the recent experience of network regulation in Britain, situating it within the conceptual lens of whole system transitions and reconfiguration. As outlined in Section 2 of the paper, the challenge facing incumbent actors, such as energy regulators and network companies, is to adapt and reconfigure an established regulatory regime which was developed in the 1990s and 2000s. In the liberalised model, the networks were unbundled – separated – from the generation and retail markets and regulated

[2] Documentation on the Energy License Modification Appeal 2023 is available at: https://www.gov.uk/cma-cases/energy-licence-modification-appeal-2023

monopolies were incentivised to operate their assets efficiently and to minimise capital investment. This segmentation and specialisation in the value chain was designed to promote competition and to drive down on costs. It was implemented in an era of relatively predictable demand growth for electricity and rested on an assumption that the networks could be adapted and reconfigured incrementally, through decentralised system planning and multi-annual price control reviews.

Our analysis of low carbon technologies and regional distribution networks in Britain highlights how key assumptions underpinning this regime can now be called into question. As discussed in Section 2, network operators are now faced with uncertainties about technological change, future demands and policy commitments to decarbonisation. Key incumbent actors – the regulator and the network companies – are seeking to manage these uncertainties by incrementally adapting and reconfiguring the regulatory regime.

In their efforts at reconfiguration these actors are seeking to address fundamental challenges inherent in the liberalised regulatory model. The first is a coordination problem: Rapid and potentially disruptive technological changes are unfolding across the electricity system, at both the supply and demand sides. The highly unbundled industry structure, with the networks treated as regulated assets, largely in isolation from generation and supply, is now recognised as ill-equipped to deal with the whole system nature of the net zero energy transition. The second challenge facing incumbent actors in regime reconfiguration is managing conflicting temporalities of change: Under incentive regulation, network investments are evaluated through periodic reviews conducted by regulators, typically every 3–8 years. However, this planning and regulation framework is not in line with net zero timescales which are set through legislative targets stretching out to 2050.

A key feature of the case analysed here is the increasing salience of net zero scenarios in system planning process and the regulatory appraisal framework. The use of scenarios in this case goes some way to addressing the fundamental problems of coordination and conflicting temporalities of change across the value chain. This has required the network companies to consider broader system level uncertainties in their business planning, particularly related to the changing uses of electricity in the transport and heating sectors.

Net zero aligned scenarios are also being used to bridge the gap in timescales and address conflicting temporalities of change. Their use is an attempt to address fundamental shortcomings of the incumbent regulatory regime, without having to revert to more traditional methods of long-term centralised planning. To deal with the risk of underfunding 'uncertainty mechanisms' were introduced by the regulator, through which additional revenues can be awarded within the price control period. These adjustments can be made only around specific areas of expenditure and based on predefined criteria, such as additional revenue for secondary reinforcement of the network if the roll out of heat pumps and EVs is more rapid than expected.

However, despite this established framework for delegation and decentralised network planning, the regulator was concerned about the quality of the DNO forecasts and associated investment plans, and thus adjusted according to a single scenario with conservative forecasts for low carbon technologies. The application of a common scenario has meant that the initial rationale for delegating planning to the DNOs – to consult with stakeholders and attune their business plans with local-regional transition pathways – was undermined. This ambiguity and inconsistency in the approach to incorporating long-term scenario planning into the regulatory model then had negative consequences for the regulator as one of the companies successfully challenged the resulting cost allocation decision in a legal case.

The decision to base allowances on a conservative scenario and adapt incrementally around this through the uncertainty mechanisms, is an adaptation of the price control framework and incentive regulation model. Underpinning this attempt at reconfiguration is a tension between decentralised network planning processes and approaches to regulatory appraisal and cost assessment which are predicated on an ability to benchmark across companies. If demand-side net zero transitions become more regionally and locally specific, the ability of the regulator to evaluate network companies using traditional frameworks and methodologies inherited from the liberalised era will become increasingly problematic, and even redundant.

While this attempt at regime reconfiguration based on decentralised scenario planning and uncertainty mechanisms has novel features, we find that the interaction between net zero and the established regulatory framework was problematic in this case. As discussed in Section 2, delegating the planning function to the companies and using incentives has been a cornerstone of the RIIO model since its introduction in the early 2010s. However, the use of net zero scenarios in regulatory decision making and their legitimacy as planning tools is yet to be fully established. We identified conflicts between ambitious investment proposals and the regulator's interpretation of its main duty to incentivise the companies to push down on costs. In the absence of clear guidance from government about the need for strategic investment – ahead of need – it is likely that regulators will remain cautious, conscious of the risk that companies will game the system and extract excessive profits. While this may appear to 'protect the interests of consumers' in the short run, it may be the case that future consumers will face higher bills than would otherwise be the case as the costs of inaction outweighs the benefits of risk aversion and short-term cost reduction.

6. Conclusions

In this paper we have provided a detailed account of the most recent regulatory review for electricity distribution networks in Britain. Based on this, we have observed how uncertainty arising from the direction and speed of technological transitions is now a much more prominent feature of the regulatory regime than had been the case in the liberalisation era. The analysis conducted here provides insights into the processes through which incumbent actors are seeking to reconfigure electricity networks and align their development with net zero system developments and timescales of transition. While the extant literature reviewed in Section 2 on transitions in regulated networks (Bolton and Foxon, 2011; Bauknecht, 2012; Bauknecht et al., 2020; Lockwood, 2023; 2016) has emphasised innovation processes within regulated network companies themselves, this case highlights that the need for innovation is now at the level of the entire socio-technical 'regime' – the web of connections between technical systems, institutions and decision makers. This is in the sense that uncertainty associated with the uptake of low carbon technologies is creating a need for greater alignment across different parts of the energy value chain.

As a result, the role of regulators is fundamentally altered, from incentivising efficiency in a particular segment of the energy chain – the monopoly networks – to aligning network transitions with wider changes in the supply and demand sides of electricity systems. This will demand a closer alignment of regulators with government energy policy and long-term strategy, along with the uneven pathways and contingencies of local-regional level system changes. Positioning network regulation as part of an evolving and dynamic socio-technical system in this way points to a new framing of regulation in relation to system transitions, one which is focused on dealing with uncertainty and long-term strategic direction, as opposed to short term optimisation and cost minimisation.

While this paper has examined reconfiguration processes in the specific case of electricity distribution networks in the British context, the tension between net zero and the incumbent regulatory regime for the networks will be observed in countries which have adopted the liberalised electricity market model and have made commitments to decarbonise their power systems. Although highly context specific, the particular case analysed here can provide broader lessons, firstly because Britain's regulatory model – based on incentive regulation – has been influential internationally (Rious and Rossetto, 2018; Joskow, 2024), and secondly, because of the uncertainties around heating and transport electrification pathways which are present in many countries committed to net zero.

A productive line of future research arising from this paper is the framing of network transitions as regime reconfiguration processes, through which incumbent actors – network operators and regulators – seek to manage uncertainty and align network developments with broader systemic changes in the supply and demand sides of the electricity sector. For the case of electricity distribution in Britain, a new price control period will commence from April 2028 and will cover a crucial period of the energy transition, given the government's objective to have a net zero power system by 2035. Depending on the scenario, projections show that the electrification of heating and transport will involve deep penetration of low carbon technologies over this period.

The British experience raises the question of whether a reconfiguration of the liberalised regime which integrates long-term scenario planning with the established regulatory framework is sufficient for the challenge of delivering net zero aligned network transitions. To inform this there is a clear need for cross-case analysis, comparing how regulators in similar institutional contexts and facing a decarbonisation imperative attempt to manage the inherent technological and societal uncertainties associated with net zero transitions. There is also a need analyse experiences in regulatory environments which are based on a tradition of centralised planning to investigate radically alternative models, their attributes and limitations.

CRediT authorship contribution statement

Ronan Bolton: Writing – review & editing, Writing – original draft, Methodology, Investigation, Funding acquisition, Data curation, Conceptualization. **Helen Poulter:** Writing – review & editing, Methodology, Investigation, Data curation.

Declaration of competing interest

The authors report no conflicts of interests associated with this study.

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Data availability

The authors do not have permission to share data.

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