An Assessment of Alternative DSO Governance Models

Prepared for Scottish and Southern Electricity Networks

23 March 2022
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Executive Summary

Key Conclusion and Recommendation

In 2022 Ofgem will undertake a review of Distribution System Operator (DSO) governance arrangements, building on the prior experience of the separation of the Electricity System Operator (ESO) and Transmission Owner (TO) roles in transmission. In this report commissioned by Scottish and Southern Electricity Networks (SSEN), we identify and assess alternative DSO governance models, perform a top-down assessment of the costs and benefits associated with alternative models, and evaluate their impact on economic welfare. The top-down analysis relies on several informed assumptions deriving from past case studies as well as discussions with SSEN. After quantitatively estimating the cost of separation, we estimate the required threshold of benefits that would need to be achieved to offset the costs of separation.

We find that any form of separation beyond ring-fencing will likely lead to negative net welfare effects. This is because the costs from legal separation or ownership unbundling would only be offset by required benefits significantly higher than our estimate of 1 to 2 per cent of avoidable expenditure by Distribution Network Operators (DNOs) that comes from these more significant separation options.

To the extent there are benefits associated with DSO separation, they arise from avoiding perceived conflicts of interest the integrated DSO-DNO may have to favour network solutions over alternatives provided by Distributed Energy Resources (DERs). However, we find these benefits are likely to be extremely small, mainly because regulatory mechanisms already exist to mitigate any such conflicts of interest. We also find that DSO separation would interfere with achieving net zero, by absorbing substantial time and resources needed to achieve net zero and make transition to net zero more costly.

However, while based on our top-down assessment the most cost-beneficial solution is DNO and DSO integration (i.e., maintaining the status quo), we recommend pursuing ring-fencing over the coming ED2 control period. Ring-fencing would help avoid the perception of conflicts of interest, giving DERs greater confidence in flexibility markets. It will allow time for DNOs to develop their DSO capabilities in the coming years, without the loss of management time that would be caused by more severe business separation. It also leaves open the option for Ofgem and government to pursue other separation options in the future, if evidence emerges that conflicts of interest exist, and the benefits of separation are material.

The Policy Debate Regarding DNO-DSO Governance Arrangements

Decarbonisation of the generation mix, decentralisation of supply, and digitalisation of the power system are changing rapidly the electricity sector. While DNOs have historically taken a role of managers of passive infrastructure, they are now required to manage the system more actively in real time and coordinating local markets for flexibility. This new emerging role is commonly described as the DSO role. Given the anticipated growth of DERs, the DSO will be crucial in the transition of the British electricity system to net zero.

Because DNOs own network infrastructure and are currently responsible for procuring alternatives to it, there is a question as to whether the integrated DSO-DNO business model can achieve an economically efficient balance between network and non-network solutions,
without distorting and limiting the market for flexibility services. Similar concerns at the transmission level led Ofgem and BEIS to separate the Electricity System Operator (ESO) from the Transmission Operator (TO). BEIS and Ofgem are therefore considering which degree of separation, if any, is needed in the DNO-DSO context. Possible governance models include ring-fencing, legal separation, ownership separation, and even amalgamation with the ESO.

While the debate on ESO separation will affect stakeholders’ thinking on whether the DSOs should be separated from the DNOs, transmission and distribution systems are different in many ways. The SO function within National Grid was established and operated for over 15 years before being separated, whereas the DSO function has only recently emerged. Hence, no evidence of conflicts of interest between the DNO and DSO can have emerged. The nature of distribution system investments is also substantially different from transmission, with DNOs requiring far more interventions on their networks than TOs, which would potentially need to be coordinated and approved by the DSO.

As well as considering possible governance models, we have also defined (working with SSE) a range of possible definitions of the business activities that could be included within the separated DSO business. Hence, we also assess evidence on the costs and benefits of different options regarding the scope of activities that the separated DSO could undertake. We label these options “Narrow”, “Wider” and “Widest”, with the “Widest” option capturing the option with the DSO taking on the largest role.

The Potential Benefits from DSO Separation are Negligible

The main possible benefits from separation of the DNO and DSO roles arise from the avoidance of conflicts of interest. Ofgem’s impact assessment of ESO separation considered two main sources of benefit: avoidance of distortions to competition in the competitive procurement of networks, and an avoidance of asset ownership bias. However, these benefits applied to distribution are smaller and less relevant than they would be in transmission:

- The avoidance of distortions to competition in competitive procurement of networks is only a theoretical concern in the distribution sector as competitive procurement of networks is at a very early stage of development and has yet to be applied at the transmission level. Even if benefits exist, these would be much lower than at transmission given that investments in distribution networks tend to be small and made on a continual basis, rather than the fewer, large, discrete investments required in transmission.

- The avoidance of an asset ownership bias may exist in theory but would be materially smaller than in transmission, where Ofgem/FTI has assumed – without any published justification – that the bias increased total expenditure between 1 and 10 per cent. The design of the current regulatory framework in distribution, primarily through the totex incentive mechanism (applied to all costs, including operating and capital expenditure as well as costs for procuring flexibility services from third parties) and the emergence of local markets for flexibility, already provide important mitigants to this problem. Therefore, we find that if any benefits may exist of avoiding asset ownership it is unlikely to be more than 1-2 per cent of avoidable expenditure.
Overall, we conclude that the benefits of DNO-DSO separation are likely negligible with the conflicts of interest either absent or already mitigated for under existing rules and regulations.

**The Potential Costs of DSO Separation are Substantial**

Quantifiable costs of separation include the one-off costs of implementing business separation, as well as the loss of economies of scope due to the duplication of currently shared activities and costs (e.g., IT, finance, premises). However, many of the costs associated with separation remain unquantifiable and are associated with a loss of operational and informational synergies from operating the DNO and DSO separately, the loss of intangible synergies such as leveraging currently shared know-how and capabilities, and the loss of financial synergies.

We quantify the cost of separation due to loss of economies of scope and one-off costs of separating the DSO and DNO using a top-down approach drawing on empirical evidence from past literature and case studies from other sectors, the costs incurred by National Grid for ESO legal separation and our own assessment of the costs shared between the DNO and DSO. However, significant unquantifiable costs mean our estimated costs of business separation are likely conservative.

We find that separation costs rise with the degree of functional separation as well as with the level of business separation. Overall, our analysis shows that, regardless of the degree of DNO-DSO separation, the costs of separation would be substantial, and could be up to around £2.8 billion in Present Value (PV) terms at the GB level. This equates to around £41 (2020/21 prices) for a typical residential customer.

**Overall, DSO Separation Will Have a Negative Impact on Consumers**

The high costs of separation mean that Ofgem and government would need to make a very clear case that benefits exist before deciding to incur them. While quantitively assessing the costs of separation is possible, estimating the potential benefits from separation is qualitative in nature. We therefore estimate the required percentage reduction in avoidable expenditure needed to offset the costs associated with each form of separation (see Table 1).

<table>
<thead>
<tr>
<th></th>
<th>Ring-Fencing</th>
<th>Legal Separation</th>
<th>Ownership Separation</th>
<th>ESO Amalgamation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Narrow</td>
<td>0.5%</td>
<td>1.3%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wider</td>
<td>0.8%</td>
<td>2.0%</td>
<td>4.2%</td>
<td>5.9%</td>
</tr>
<tr>
<td>Widest</td>
<td>1.0%</td>
<td>2.5%</td>
<td>5.3%</td>
<td>7.3%</td>
</tr>
</tbody>
</table>

*Source: NERA analysis.*

Given our finding that the potential benefits of separation are unlikely to be more than 1 to 2 per cent of DNOs’ avoidable expenditure, the results of our analysis suggest that the costs of legal and ownership separation, and ESO amalgamation, are significantly greater than the
possible benefits. These forms of separation require cost savings of at least 4.2 per cent which is unlikely in distribution.

Our analysis shows that only ring-fencing has potential for a positive cost-benefit trade-off. The ring-fencing option would be relatively low cost to implement and would come with few downside risks, although it may be less effective in avoiding existing or perceived conflicts of interest.

We also find that the “Wider” definition of the DSO is preferable if ring-fencing is pursued. This is because the “Widest” definition involves the DSO taking day-to-day decisions on the operation of the network, with its role extending beyond planning and the procurement of flexibility services as in the “Narrow” and “Wider” options. This creates the potential for operational difficulties in the DNO-DSO interface that would harm customers. The “Narrow” option has lower net benefits than the “Wider” option because the “Narrow” option does not include the evaluation of alternative system solutions among its functions, a key area where perceived asset ownership bias exists.

Hence, while our analysis suggests the most cost-beneficial solution is DNO-DSO integration, we recommend pursuing ring-fencing a Wider DSO over the coming ED2 control period due to the limited downside risk and optionality for both industry and Ofgem to pursue further separation if new evidence emerges that further business separation is necessary.

**DSO Separation Would Interfere with Achieving Net Zero**

The decision regarding possible governance arrangements in the DNO-DSO context will also have implications with respect to achieving net zero. The decarbonisation targets set by the UK government require high levels of investment and human capital, as well as coordination among all stakeholders in the supply chain for electricity. Particularly distribution and transmission will have a crucial role, accommodating new means of flexible generation and connection to the grid. If DNOs devote very significant resources to the separation of DNOs and DSOs while working toward net zero, this could substantially interfere with achieving net zero and increase the costs of the transition to net zero, by increasing the levels of coordination required at the industry.
1. Introduction and Background

1.1. The Need for Policy Choices on DSO Governance Models

The process of decarbonising the UK’s energy supply and achieving net zero emissions will transform the electricity system, particularly at the distribution level. As described in National Grid’s latest Future Energy Scenarios (FES), electricity demand is set to substantially increase as transport and heating are electrified.\(^1\) Meanwhile, the electricity generation system is becoming increasingly decentralised as Distributed Energy Resources (DERs), which operate at the distribution or end user level, feed power onto the network. To ensure increasing demand is accommodated efficiently, the Distribution Network Operators (DNOs) will need to adopt a more active role in managing their own systems.

As set out by Ofgem, this new “Distribution System Operator” (DSO) role should ensure the efficient and effective development and use of the distribution system in a context of increasing flexibility, technology and digitalization, whilst ensuring system and cyber security and resilience.\(^2\) In practice, the DSO should support the energy system in harnessing the flexibility that comes from using DERs to manage congestion in distribution systems, and therefore moderate the very large investments that will be required to reinforce them, as well as manage the impact of flexibility on the wider system.

In this context, we understand that during 2023 Ofgem will be undertaking a detailed review of the existing DSO governance arrangements by considering options for alternative governance models or allocation of responsibilities between the DNO and DSO to alleviate potential issues of conflict of interest and ensure neutral decision-making, such as between investment and flexibility technologies.\(^3\)

As outlined in the recent joint consultation document published by Ofgem and BEIS on the future energy system operator, Ofgem will consider several alternative governance models for the DSO including but not limited to functional separation, legal separation, through to full ownership separation. The functions that could be separated could be one, some, all or a subset of the DSO functions identified by Ofgem at RIIO-ED2, namely:\(^4\) planning and network development, network operation, and market development. Also, Ofgem may consider having other parties perform some of these functions, including potentially the ESO.\(^5\)

1.2. Our Scope of Work and Approach

Against this background, NERA Economic Consulting (NERA) has been commissioned by Scottish and Southern Electricity Networks (SSEN) to assess alternative DSO governance models. Our objective is to provide evidence on the costs and benefits of alternative DSO governance models to help inform the upcoming policy choices by BEIS and Ofgem in this

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1 National Grid (July 2021), Future Energy Scenarios 2021, p. 44.
2 Ofgem (28 August 2020), Next steps on our reforms to the Long-Term Development Statement (LTDS) and the Key Enablers for DSO programme of work, p. 1.
4 Ofgem (17 December 2020), RIIO-ED2 Sector Specific Methodology Decision: Overview, p. 77.
area, and therefore ensure that any proposal for a new DSO governance model benefits consumer by enabling net zero at lowest cost, whilst protecting security of supply.

1.3. Limitations

Our quantitative analysis has adopted a rigorous and evidence-based approach. However, there are several limitations to our analysis, which we summarise in turn below.

There is no direct evidence on the costs of separation from the electricity distribution sector. An accurate estimate of the costs of DSO separation under each separation option would require a data gathering process by DNOs followed by an assessment of submitted costs by Ofgem, in line with the process followed by Ofgem for the legal separation of the Electricity System Operator (ESO).

In the absence of actual data across the companies, we have adopted a top-down approach to estimating the cost of alternative DSO governance models by relying on a number of sources, including: the actual costs of ESO legal separation from National Grid, economic literature on the economies of scope in the electricity sector and on the costs of unbundling different parts of the electricity value chain, as well as studies and evidence from other sectors (e.g., water). It follows that given the limited access to actual cost data, some estimates of the costs of separation are inevitably driven by assumptions, albeit tested against the literature and other evidence.

We have also relied on publicly available data for the DSO costs over ED2 and cost information provided by SSE. This data reflects SSEN’s and SSEH’s final ED2 business plans data and ENWL’s published draft ED2 business plan data and therefore may not reflect different DSO and DNO corporate structures and allocation of costs. Any changes to the cost forecast or assumptions will impact the results presented in this report.

To estimate the costs and benefits we have relied on our own modelling and forecast of total expenditure and revenues over a modelling horizon up to 2050. This modelling relies on our detailed understanding of the RIIO regulatory framework, public information regarding forecast expenditure and cost drivers, and our own assumptions regarding future expenditure growth. As for the DSO costs, at the time of writing this report, we only have ED2 final business plans data for SSEN, while for the other DNOs we rely on their ED2 draft business plan data. Any changes in the final and actual expenditure allowed at RIIO-ED2 or other regulatory parameters will necessarily impact the results presented in this report.

Finally, as we discuss in this report, there are a number of unquantifiable costs associated with alternative DSO governance models, which suggest that the results presented in this report could be understating the total costs of DSO separation.

1.4. Structure of the Report

The remainder of this report is structured as follows:

- Chapter 2 describes the evolving role of the DSO in the British energy market;
- Chapter 3 identifies and describes the alternative DSO governance models that we assess in this report;
- Chapter 4 sets out the potential advantages of separation of the DNO and DSO;
• Chapter 5 sets out the potential disadvantages of DNO-DSO separation;
• Drawing on the analysis of advantages and disadvantages, Chapter 6 then brings together our assessment of the net benefits of separation for the alternative models of separation discussed in Chapter 3;
• Chapter 7 discusses the effects of separation on the ability of achieving net zero; and
• Chapter 8 concludes.

Appendices provide further details of our research and analysis presented in this report.
2. **Background on the Policy Debate Regarding DSO Unbundling**

2.1. **Emergence of DSO Activities within the Existing DNOs**

DNOs have historically been responsible for expanding, maintaining, and operating the distribution networks in their service areas as well as meeting public policy requirements placed on them. Until recently, DNOs provided these services primarily through their own operational activities (e.g., maintenance, fault restoration capability, and vegetation management) and capital investments (e.g., replacement and reinforcement of the network).

However, the energy system is changing rapidly, shaped by the decarbonisation of the generation mix and electrification of demand from heating and transport, with the growth of Distributed Energy Resources (DERs) causing the decentralisation of supply to smaller scale facilities, and digitization enabling new technologies. Simultaneously there continues to be strong public, regulatory and political focus on the cost of energy paid by consumers. These pressures create new demands on DNOs to contribute to the delivery of legally binding net zero targets by providing incremental system capacity to manage growing system requirements.

Greater decentralisation and digitalisation also enables DNOs to adopt new means of meeting these requirements, which increasingly requires a new trade-off between traditional wire-based asset solutions and the flexibility offered by DERs. DERs are fundamentally different from traditional wire-based solutions. Using DERs to provide network capacity requires a contract with a third-party provider via a “flexibility contract” struck with the DNO, and additional real-time optimisation of the local system to dispatch the contracted flexibility providers. There are therefore new roles emerging within the DNO business to manage these contracts, which can involve:

- Network planning and development: planning efficiently in the context of uncertainty, taking account of whole system outcomes; and promote planning data availability;
- Network operation: promoting operational network visibility and data availability; and facilitating efficient dispatch of distribution flexibility services; and
- Market development: providing accurate, user-friendly, and comprehensive market information; and embedding simple, fair, and transparent rules and processes for procuring distribution flexibility services.

These new roles involve a transition, from the primary role of the DNO as a manager of infrastructure to a new role of more actively managing the system and demand in real time and coordinating the market for flexibility in the DNO’s local area. This new role is commonly described in the British electricity industry as the emerging Distribution System Operator (DSO) role.\(^7\)

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\(^6\) Ofgem (17 December 2020), RIIO-ED2 Sector Specific Methodology Decision: Overview, p. 77.

\(^7\) Note, in Continental Europe the term DSO has already been used for some time to refer to ownership, operation, maintenance and development of the distribution system, i.e., the roles described above as relating to the DNO function. In New Zealand, the term DSO has broadly the same meaning as in Great Britain.
The new DSO role will play an important part in helping the British energy system transition to net zero, given the anticipated growth in DERs. For example:

- Akorede et al. (2010) find that DERs, particularly distributed generation, could mitigate the environmental impacts of fossil fuel-based power generation, reducing GHG emissions, improving energy efficiency, and reducing damage to human health.\(^8\)

- Also, Strbac et al. (2019) conclude that DERs can contribute to the provision of system balancing as well as support a cost-effective transition to a low carbon energy system.\(^9\)

- In 2016, a fundamental review of Engineering Recommendation P2/6 commissioned by the Distribution Code Review Panel (DCRP) P2 Working Group found that managing network overloads through a wider use of DERs creates significant potential to reduce the level of redundancy in physical network assets by harnessing flexibility resources.\(^10\)

- The Carbon Trust and Imperial College (2021) assess the role and value of flexibility in Great Britain with a particular focus on heating. Amongst other things, they find evidence of several system benefits, arguing that flexibility, for example provided by energy storage and other DERs, helps balance demand and supply, and decreases peak electricity demand yielding reduced reinforcement costs.\(^11\)

Despite the importance of the DSO role in the future, as explained further in Section 2.2.1 below, the DSO role has only been identified in policy and regulation relatively recently and the scope and scale of the DSO role remain subject to wide uncertainty and potential evolution over the coming years. Currently, its role is limited due to the limited role that flexibility from DERs plays in the market and unless flexibility emerges at scale at the distribution level (including through flexibility in the domestic market, and not only at the industrial level), the role of the DSO will also remain necessarily limited in scope.

Indeed, despite growing rapidly, the market for flexibility services (which allows DNOs to use DERs to manage local system constraints) is also relatively new: DNOs’ use of flexibility has grown from 116MW in 2018 to 1.6GW in 2021.\(^12\) This growth in flexibility has not been uniform across Great Britain, because of different network needs and local policy considerations. Thus, geographical variations could remain in the evolution phase of a flexibility market, and DNOs will likely need to develop DSO capabilities at different times.\(^13\)

Therefore, the DSO role and the flexibility markets are both nascent. While DERs have enormous potential to offset distribution system requirements, the scale of their future role may evolve over time, including opportunities for local balancing energy mechanisms and

\(^8\) Akorede, M. F. et al. (2010), Distributed energy resources and benefits to the environment, *Renewable and sustainable energy reviews*, 14(2): 724-734.


\(^11\) Carbon Trust & Imperial College (2021), Flexibility in Great Britain, p. 20.

\(^12\) 1609 MW of contracted flexibility up to 30 July 2021. Data source: ON21-WS1A-Flexibility s 2021 Full Update (30 Jul 2021).

associated ancillary services, and greater coordination at the ESO / DSO interface. In this context, as wholesale energy prices rise or become more volatile, the role of the DSO may be less focused on procuring and using flexibility to offset network investments, but rather enabling constrained flexibility to participate in the national energy, ancillary services, or balancing markets by unlocking required network capacity when efficient.

2.2. Parallels Between Distribution and Transmission System Operation

2.2.1. While there are similarities between the TSO and DSO functions, the TSO function has been established for many decades

As noted above, the concept of a DSO that actively manages its network and procures services from third party DERs is relatively new. For example, although Ofgem was starting to consider the role of an electricity DSO in 2010, there was only limited discussion of the DSO role in DNOs’ business plans at RIIO-ED1.14

By contrast, at the transmission level, active management of the network in real time, and making trade-offs between investments and other non-asset solutions when planning the network, has been a feature of the electricity industry (in Great Britain and around the world) for decades:

- It has always been necessary to ensure interconnected power systems can balance supply and demand through real time dispatch decisions, and integrated power system planning has a long track record of considering trade-offs between transmission capacity and payments to generators through the balancing mechanism and ancillary services market.
- For instance, transmission infrastructure can alleviate congestion that would otherwise require interventions by the transmission System Operator (SO) in the balancing market, and/or improve the stability of the power system to reduce the need for ancillary services procured from third parties.

The SO role has been performed by National Grid Plc throughout Great Britain since the introduction of the British Electricity Trading and Transmission Arrangements (BETTA) in 2005 and, despite taking different forms since privatisation, it has therefore been operating and developing for more than 16 years now. For instance, additional SO roles like such as assessing alternative options to meet network needs have been undertaken by the SO since the Integrated Transmission Planning and Regulation (ITPR) process in 2015.15 Also, even before the full legal separation of the ESO, the SO function was already separated through separate data reporting requirements for the purpose of setting price controls and annual regulatory reporting. Unlike the SO, the concept of DSO has been identified only recently by Ofgem in the context of the RIIO-ED2 process and DNOs have only been procuring flexibility services since 2018.

It follows that unlike the DSO role, the SO role has a much greater maturity and while the development of DSO capabilities and responsibilities within the DNO businesses have

14 Ofgem (4 October 2010), Regulating energy networks for the future: RPI-X@20 Recommendations, Box. 1.
15 Ofgem (17 March 2015), Integrated Transmission Planning and Regulation (ITPR) project: final conclusions, p. 9.
similarities to the SO role at the transmission level, it is much less established than at the transmission level.

2.2.2. Concerns about potential conflicts of interest have led to vertical separation at the transmission level

The transmission and distribution systems provide essential facilities to enable the supply of electricity to consumers from generators. However, while there is the potential for competition in generation and retailing, transmission and distribution systems are natural monopolies in which the potential for competition is inherently limited.

Given this industry structure, there is a long-standing debate as to the costs and benefits of vertical integration between the natural monopoly transmission and distribution networks and the competitive generation and retail segments of the market. The debate arises because of the potential for vertical foreclosure: the natural monopoly transmission or distribution network operator may have an incentive to take decisions that favour its generation or retail affiliates.

In the transmission sector, this concern led to the full ownership separation of the SO function from generation and retail interests, with legal separation requirements between the Transmission Owner (TO) function and affiliated generation and retail interests. Further to that, there has also been a debate about the need for separation of TOs from the system operation function.16

In Great Britain, this led Ofgem to mandate the legal separation of the Electricity System Operator (ESO) business from the rest of National Grid Electricity Transmission, and to issue the consultation on establishing an independent Future System Operator (FSO) with proposed additional roles. The case for separating the ESO comes from two perceived risks, that:

- Planning decisions by a SO that also owns a TO business will lead it to favour asset-based solutions over those provided by third parties like storage, generation, etc; and
- Ofgem’s ambitions to subject the TOs to competition in the provision of network investment which require competitive procurement by an SO that is (seen to be) a neutral party, which may not be possible without legal separation of the SO from its affiliated TO.

Separation of the SO and TO functions has the potential to alleviate these conflicts of interest, though at a cost. As we further explain in Chapter 5 of this report, ring fencing arrangements, legal separation, and ownership unbundling all impose costs of implementing new arrangements and ongoing losses of “vertical economies” from operating an integrated business. These costs may be substantial, especially where it is necessary to create and operate new businesses.

In the case of transmission, Ofgem assessed that the benefits of avoiding these conflicts of interest outweighed the costs of separation, and in August 2017 mandated that the SO should

16 Papers that have contributed to this debate include (1) Pollitt, M. (2008), The arguments for and against ownership unbundling of energy transmission networks, Energy Policy, 36(2): 704-713; (2) Brunekreeft, G. et al. (2005), Electricity transmission: An overview of the current debate, Utilities Policy, 13(2), 73-93; and (3) Sugimoto, K. (2021), Ownership versus legal unbundling of electricity transmission network: Evidence from renewable energy investment in Germany, Energy Economics, 99: 105290.
be legally unbundled from the rest of National Grid.\(^\text{17}\) With a view to further expanding the SO responsibilities, including government advisory, system coordination, dispute resolution and so on, Ofgem and BEIS issued the recent consultation on establishing an independent electricity and gas SO.\(^\text{18}\)

### 2.2.3. Ofgem is considering whether greater DNO-DSO separation is needed

Changes in the role of DNOs to include DSO activities have created similar concerns about whether a DSO that is integrated with a DNO business can act as a genuinely neutral third party in activities like network planning and flexibility procurement. Ofgem has suggested that in some cases DNO participation could have negative distortions. While allowing DNOs to compete with each other and with other parties to offer flexibility services may be efficient in some cases, Ofgem notes that “[w]here the DNO is participating in a market, real or perceived conflicts of interest must be managed to promote a level playing field across service providers and lower barriers to entry for new participants”.\(^\text{19}\)

Ofgem has already prevented DNOs from operating storage, in line with the provisions set out at the European level,\(^\text{20}\) and has recently consulted on their involvement in network voltage control and management services procured by the ESO.\(^\text{21}\)

Moreover, similar to its consideration of business separation options at the transmission level, Ofgem has also stated that it “will consider whether there may be a case for greater separation of certain DSO functions from the ‘traditional’ DNO functions, or any wider reforms to institutional arrangements at distribution level”.\(^\text{22}\)

In the Sector Specific Methodology Decision for the RIIO-ED2 price control,\(^\text{23}\) Ofgem states it intends to ensure DNOs continue to develop DSO capabilities and functions over the ED2 period. For instance, it proposes to introduce a new DSO incentive framework for ED2, complemented by a new Output Delivery Incentive (ODI) that will allow Ofgem to undertake an ex-post review of DNOs’ delivery of their DSO activities to encourage innovation.\(^\text{24}\)

Ofgem describes the baseline expectations for this ODI as:

- Planning efficiently in the context of uncertainty and promoting planning data availability (planning and network development);
- Promoting operational network visibility and data availability and facilitating the dispatch of distribution flexibility services (network operation); and

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\(^\text{17}\) Ofgem (3 August 2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, p. 15.


\(^\text{19}\) Ofgem (6 August 2019), Position paper on Distribution System Operation: our approach and regulatory priorities, p. 13.

\(^\text{20}\) Ofgem, (20 December 2018), Decision on enabling the competitive deployment of storage in a flexible energy system: Changes to the electricity distribution licence, p. 1 and p.3.

\(^\text{21}\) Ofgem, (10 February 2020), Regulatory treatment of CLASS as a balancing service in RIIO-ED2 network price control.

\(^\text{22}\) Ofgem (6 August 2019), Position paper on Distribution System Operation: our approach and regulatory priorities, p. 6.

\(^\text{23}\) Ofgem (17 December 2020), RIIO-ED2 Sector Specific Methodology Decision: Overview.

\(^\text{24}\) Ofgem (17 December 2020), RIIO-ED2 Sector Specific Methodology Decision: Overview, p. 56-57.
• Providing accurate, user-friendly, and comprehensive market information and implementing processes for procuring distribution flexibility services (*market development*).\(^{25}\)

The Sector Specific Methodology Decision also discusses Ofgem’s concerns regarding potential conflicts of interest between the DNO and DSO functions. For example, Ofgem recognises that “there could be merits to alternative governance models or allocations of responsibilities”.\(^{26}\) Ofgem has therefore required DNOs to identify costs associated with flexibility and DSO operations separately in their business plans to ensure that ED2 policy does not form a barrier to separation of DNO and DSO roles in the future.\(^{27}\)

Ofgem has further stressed the importance of the DNO-DSO transition in its ED2 Business Plan Guidance.\(^{28}\) Ofgem has requested DNOs to submit their DSO strategies together with their business plans, including the planned measures to mitigate potential or perceived conflicts of interest as well as justification of DNOs’ proposals supported by relevant information on likely costs, timings, and implications of alternative governance models (where available).\(^{29}\)

As noted in Section 1.1 above, in the joint BEIS and Ofgem consultation of an independent Future System Operator (FSO), it is stated that in 2023 Ofgem will undertake a detailed review of the DSO governance arrangements. Although Ofgem has never found National Grid plc to act upon any potential conflict of interest, it notes that “the perception of conflicts of interest itself creates inefficiency, even if no actual conflicts are present”.\(^{30}\) However, Ofgem and BEIS have not yet put forward any evidence on the scale of potential benefits, or the offsetting costs of separation. As outlined in the consultation document, Ofgem will consider options for alternative governance models or allocation of responsibilities between the DNO and DSO to alleviate potential issues of conflict of interest and ensure neutral decision-making, such as between investment and flexibility technologies.\(^{31}\)

Ofgem will consider several governance models including functional separation, legal separation, and full ownership separation.\(^{32}\) The functions that could be separated could be one, all or a subset of the DSO functions identified by Ofgem at RIIO-ED2 (and listed above). Also, Ofgem may consider having other parties perform some of these functions, including potentially the ESO.\(^{33}\)

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\(^{25}\) Ofgem (17 December 2020), RIIO-ED2 Sector Specific Methodology Decision: Overview, p. 77.  
\(^{26}\) Ofgem (17 December 2020), RIIO-ED2 Sector Specific Methodology Decision: Overview, p. 62.  
\(^{27}\) Ofgem (17 December 2020), RIIO-ED2 Sector Specific Methodology Decision: Overview, p. 64-65.  
\(^{28}\) Ofgem (30 September 2021), RIIO-ED2 Business Plan Guidance.  
\(^{29}\) Ofgem (30 September 2021), RIIO-ED2 Business Plan Guidance, p. 84.  
2.3. Evidence from the Literature on the Benefits of Distribution Separation

2.3.1. Evidence from literature on the benefits of unbundling suggests significant benefits of transmission unbundling

Our review of published literature has identified evidence of potentially significant benefits to unbundling of transmission from generation and supply interests. While transmission was separated from generation at privatisation in England and Wales and separated from distribution before the introduction of competitive retail during the 1990s, much of the recent discussion of these benefits come from the debate surrounding (and retrospective analysis of) the European Union’s decision to pursue ownership unbundling of transmission under the third energy package. The suspected discrimination towards third parties by integrated companies and the potential savings for consumers through unbundling led to the EU pursuing the policy.

Prior to the implementation of the third energy package, the European Commission published research supporting the need for unbundling in the energy sector. In 2007, the EU Sector Inquiry into the energy sector found that the level of unbundling in the networks at the time was having an overall negative impact and threatened security of supply. Further work for the Commission by Lowe et al. (2007) supported the need for unbundling, stating that “the current unbundling provisions as required by the Second Electricity and Gas Directives are not fully adequate”. The Sector Inquiry suspected that network operators were favouring their own affiliates and that investment decisions were not being taken in the interests of the whole network, damaging security of supply. The Inquiry also found evidence of vertical foreclosure “by way of the integration of generation/imports and supply interests within the same group”. The Inquiry found that integration of interests reduces incentives for incumbents to trade of wholesale markets leading to sub-optimal liquidity. In particular, the report cites the prevalence of long-term power purchasing agreements giving incumbents control over essential inputs into the wholesale market.

Following the Sector Inquiry, the Commission introduced more stringent unbundling requirements and whilst wider evidence from academic literature is less supportive about the benefits of ownership unbundling in transmission, there is consensus that legal unbundling has significant benefits. Heim et al. (2020) find that the move to legal unbundling in transmission has had a significant effect in reducing grid charges. Brunekreeft (2008) finds for German Transmission System Operators (TSOs) that the net social cost benefit effect is

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likely positive but small, although they find significant savings for consumers with further unbundling, at the expense of producers. These benefits are balanced against significant costs (as discuss in Chapter 6).

2.3.2. The literature suggests that the case for unbundling distribution is weaker than transmission

When considering the unbundling of distribution from generation and retail interests the literature suggests the benefits are smaller than in transmission, although the theoretical arguments are similar.

In developing the third energy package, the Commission did consider further unbundling of distribution in line with the measures taken in transmission that separate it from generation and retail interests. The Commission argued that without unbundling at the distribution level:

- Vertically integrated distribution operators have an interest to make switching procedures more difficult (to deter market entry) and incumbents may benefit from privileged access to information. 42
- There is the risk of cross subsidy when businesses are integrated and that the ownership of network assets may put vertically integrated distribution operators at a competitive advantage due to easier access to capital compared to companies without these assets. 43

However, considering the costs associated with separation, the Commission concluded that “[f]urther DSO unbundling does not seem to bring sufficient added value”. 44 The conclusion was justified due to the different nature of transmission and distribution networks, and the lack of legislative experience in unbundling distribution. This conclusion was also predicated on the assumption that distribution systems were not congested at the time when the Commission made its assessment in 2009. The Commission noted that this may change in the future (due to load growth associated with the electrification of heat and transport) and that it might therefore need to revisit its assessment. As of today, the Commission has not done so.

Academic studies also suggest the case for unbundling is weaker than in the transmission. For instance, Filippini and Wetzel (2014) find that ownership unbundling of distribution networks from retail activities in New Zealand had a positive effect on cost efficiency. Similarly, Pollitt and Nillesen (2019) find that after ownership unbundling of retail activities from distribution networks in New Zealand there were “substantial cost reductions and

increases in quality of service”\textsuperscript{45} However, the authors find that the cost reductions were not passed on the customers, and also find a reduction in overall competition. Hence, Pollitt and Nillesen (2019) find the benefit of unbundling retail activities at the distribution level to be “questionable” and recommend other policy measures to improve competition, given the questionable upside.\textsuperscript{46} Finally, citing evidence from New Zealand and the Netherlands, Pollitt and Nillesen find evidence of significant transaction costs while the upside is uncertain and “could even be negative”.\textsuperscript{47}

2.3.3. Further evidence is needed on the case for DSO-DNO separation

Specifically looking at DNO and DSO separation, Burger et al. (2019) do not recommend separation of the two roles due to the complexities of such a move in distribution, although they do recognise the need for adequate incentive regulation and a degree of independence between DNOs and DSOs. Specifically, they argue that distribution utilities should not be allowed to own DERs, given evidence that DER ownership is “best left exclusively to non-monopoly actors”.\textsuperscript{48} They argue that allowing monopoly participation in competitive activities has negative impacts and will likely result in inefficient utilisation of DER capacity.\textsuperscript{49}

Overall, Burger et al. (2019) point towards the need for stronger separation between DNOs/DSOs and any competitive actors but stop short of recommending specific unbundling of DNOs and DSOs.

The above review of the literature suggests that evidence from the academic literature on the benefits of DNO-DSO unbundling is limited, and the one which does exist does not support the need for separation. Also, most of the literature on distribution unbundling focuses on unbundling generation and retail from distribution, and – unlike transmission where there is a reasonably clear consensus that some level of separation is needed – the literature shows a much lesser case for distribution unbundling.

Finally, much of the existing literature on distribution unbundling is also dated, so does not consider the ongoing changes in the industry and the evolving role of the DNO due to decarbonisation, decentralisation and digitalisation. As such, to inform Ofgem and BEIS’s decision on potential future separation, further evidence is needed.

The remainder of this report aims to provide evidence on the benefits and costs of DNO-DSO separation, in the context of the ongoing transition of the energy sector towards net zero, and the regulatory framework in place for DNOs in Great Britain.


2.4. Conclusion

As explained above, the role of the DNO is changing rapidly to include new DSO responsibilities. The new roles DNOs will take on have generated some concerns about possible conflicts of interest leading to inefficient decisions by the DNOs, and a suboptimal use of DERs to provide the local system capacity needed to support net zero and the electrification of heating and transport.

Unlike transmission, where there is wide-spread international precedent and literature that justifies creation of independent SO functions, we are not aware of any international precedent involving the separation of DSO and DNO functions. There is also no empirical evidence of conflicts of interest between the DSO and DNO creating inefficiency, because (unlike the ESO) the DSO role and flexibility markets are new and continue to develop.

Nonetheless, the rapidly changing market and policy environment means Ofgem and BEIS plan to consider whether some degree of separation could be justified in the future.

Any decision to separate the DNO and DSO activities must be driven by evidence that separation would reduce conflicts of interest, that this would lead to efficiency improvements, and that these benefits offset the costs of doing so. As we further discuss in the Chapter 5 of this report, the loss of vertical economies that come from separation between DNO and DSO could be considerable, including both the duplication of overheads, costs of implementing business separation, and the costs of creating new interfaces and commercial arrangements between DSO and DNO.

Finally, as we discuss in Chapter 7 of this report, the significant management time and effort associated with business separation means a decision to separate the DSO and DNO businesses would also need to consider the challenges of achieving net zero, which requires the electricity to deliver significant investment and implement other regulatory changes. Hence, if human capital in the energy sector (i.e., the capacity of companies’ management, the capacity of government and the regulator) is scarce, business separation could hamper efforts to achieve net zero.
3. **Candidate DSO Governance Models**

3.1. **Identifying Alternative DSO Governance Models**

The distribution sector in Great Britain is currently organised such that all distribution activities and functions, including DSO and DNO, are performed within the same regional company, with no formal separation of activities or functions. Hence, at present the 6 companies which administer the 14 regional DNO licensees own and operate the distribution networks with voltages up to 132kV in England and Wales and below 132kV in Scotland, are responsible for ensuring the efficient and secure operation of the distribution system.  

As mentioned in Section 1.1 above, in their July 2021 consultation document, BEIS and Ofgem have stated they will consider alternative governance models, including but not limited to functional separation, legal separation, through to full ownership separation. They also stated that the functions that could be separated could be one, some, or all of the DSO planning, operation and market facilitation functions defined by Ofgem at RIIO-ED2, or a subset of these. Also, Ofgem may consider having other parties perform some of these functions, including the ESO.  

Against this background we consider twelve potential alternative options for DSO governance based on the level of business and functional separation, as illustrated in Figure 3.1 below. We discuss the choices around the levels of business and functional separation in turn below.

This report does not look at options regarding what activities and services the DSO and DNO perform, unlike the FSO review carried out by BEIS and Ofgem where there is also an assessment of the expansion of roles and organizational model for the FSO. In this report, we examine options regarding how existing responsibilities might be split between the DSO and the DNO, and the degree of separation between the DNO and DSO.

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50 Note this excludes Independent Distribution Network Operators, or IDNOs.

3.2. Degree of Business Separation

Business separation has been used by governments and regulators in many sectors in the UK and Europe, including most notably the energy and telecoms sectors, as a tool to avoid potential conflicts of interest or abuses of dominant market positions by incumbents and/or owners of natural monopoly infrastructure. Based on these precedents, we identify a spectrum of potential business separation options for the DNO and DSO functions: vertical integration (status quo), ring-fencing, legal separation, and ownership unbundling.

Assuming some move away from the vertically integrated model is required, accounting separation and ownership unbundling represent the extremes of the separation options with the others falling on a spectrum between the two, as shown by the columns in Figure 3.1.

In the context of the current changes in the electricity industry, we also consider an option to amalgamate local DSO activities with the national ESO, which has been recently legally separated from National Grid (the Transmission Owner in England and Wales). ESO amalgamation goes beyond ownership unbundling, by then incorporating the unbundled DSO into the ESO.

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52 For example, gas and electricity transmission underwent unbundling under the Gas Act 1986 and Electricity act 1989. In telecoms, local loop unbundling has been carried out since 2006.

53 For the spectrum between the two extremes see Cave, M. (2006), Six Degrees of Separation: Operational Separation as a Remedy in European Telecommunications Regulation, p. 94. Our models for DSO governance fall at points along this spectrum with sector specific adjustments made to accommodate the specific situations.
It should be noted that the outcome of any business separation is likely to be sector and case-specific. The success of separation in other sectors or instances does not guarantee its success in distribution (and vice versa).

3.2.1. Vertical integration (status quo)

Under the status quo option the DNO and DSO function are part of the same organisation, with no substantial separation or barriers between the two. Currently there is a very limited degree of accounting separation, with DSO costs being reported separately in the RIIO-ED2 business plan for example, but with no further barriers beyond this (e.g., we understand that there is no requirement for separate regulatory accounts).

Some of the DNOs may already have internally organised their DNO and DSO function across different directorates, and put in place some conflict of interest mitigation strategies in response to Ofgem’s requirements at ED2. However, in the reminder of this report we assume no strict ring-fencing rules apply, with such organisational choices made voluntarily by companies, such as through the establishment of distinct DSO directorates.

We also assume, that any costs incurred by DNOs to implement such organisational choices during ED1 and ED2, should be considered as sunk costs that the DNO has or will bear regardless from further regulatory or legal requirements for business separation.

3.2.2. Ring-fencing

Under the ring-fencing governance model, the DNO and DSO function are part of the same organisation, but stricter business separation rules and measures are put in place including:

- **Information separation**, e.g., restrictions on accessing IT systems and confidential information;
- **Separation of employees and staff** such that staff do not work both inside and outside the ring-fenced function; and
- **Physical separation** such that staff are not working amongst other staff outside the ringfence. This requires (for example) rearranging office space, partitioning offices, and placing the ring-fenced team in a secure and separate work area.

In the remainder of this report, we assume that under a ring-fenced arrangement there would be no financial or licence separation, beyond an obligation to separately report DSO costs to Ofgem in the Business Plan Data Tables and the ongoing Regulatory Reporting Packs for RIIO-ED2. This option sits approximately midway between legal unbundling and the status quo.

3.2.3. Legal separation

Legal separation means the unbundling of the DSO and DNO business units and creation of two entirely separate businesses and legal entities to host the two functions originally

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55 In the remainder of this report we assume it does not require moving staff to new and additional premises or offices.
56 See Cave, M. (2006), Six Degrees of Separation: Operational Separation as a Remedy in European Telecommunications Regulation, p. 94. Note: ring fencing would sit at around a 3 on the scale identified by Cave.
undertaken by a single business unit. Under this arrangement, ownership of the DSO and DNO function would remain within the same ownership group.

In the remainder of this report, we assume that the legal separation of the DSO-DNO functions would follow similar governance arrangements to those Ofgem sought for the ESO when it was legally separated from National Grid Electricity Transmission (NGET) in April 2019.\(^{57}\) This includes:\(^{58}\)

- **Licence and governance separation** by defining a separate DSO licence, separate from the DNO licence, which sets out the DSO roles and responsibilities, an independent and separate Board of Directors, and a Compliance Committee and Separation Compliance Officer appointed by the DSO to oversee compliance against the business separation obligations.

- **Financial separation** by requiring the DSO to have its own separate accounts to avoid cross-subsidies between the DSO and any other DNO group entities. As with National Grid ESO, we assume that the DNO group could be providing the DSO with financial assistance e.g., on debt management and working capital arrangements, to support the independent credit rating of the DSO (if required).

- **Operational separation** by introducing modifications to the industry codes to clarify responsibilities and accountabilities for operational activities and commercial arrangements between the DSO and DNO, and the DSO and other code parties, as well as reviewing relevant internal business procedures and processes to implement such changes. At the time of writing this report, it is too early in the policy debate on DSO-DNO separation to identify an exhaustive list of changes and modifications to the industry codes, and internal business procedures.

- **Information ringfencing** requiring stronger ring-fencing around information sharing and IT systems between the DSO and DNO entities, limiting to only exceptional cases the sharing of confidential and commercially sensitive DSO information with the DNO, and vice-versa.

- **Employee separation, incentivisation and transfer**, by requiring the DSO legal entity to employ DSO staff and ensure DSO managers are incentivised to achieve DSO performance metrics. Staff should also be incentivised on the performance of DSO only.\(^{59}\)

- **Physical separation** requiring the DSO staff to be relocated within physically separated premises or areas of the DNO group’s existing headquarters, with a separate entrance and staff facilities.

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\(^{59}\) Ofgem sets out its intentions for how the System Operator should be separated in August 2017. Taking into account stakeholder feedback, the joint statement is that staff should be “incentivised on ESO performance only”, although Ofgem accepts that there could be exceptions for a small number of staff. Source: Ofgem (3 August 2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, p. 16.
• **Culture & branding separation** by requiring the DSO to adopt a distinct and explicit visual identity from the DNO (e.g., new logos, imagery, and colour palettes).

Finally, in line with the NG ESO legal separation we assume that where a DNO group adopts a shared service model that allows support functions to be shared between subsidiaries of the group, that such a model can continue to exist albeit with some reviews to ensure independent decision making by the DSO. For example, we assume that the finance, corporate affairs, legal, Human Resources (HR), and Information Technology (IT) functions would put in place a dedicated business partner to deliver the strategic and operational activities they provide to the DSO. Other functions, such as tax and treasury, would continue to be shared across the DNO group.

### 3.2.4. Ownership unbundling

Ownership unbundling means the full unbundling of the DSO and DNO, through which the DSO activities and functions are divested from the DNO’s ownership group, and strict rules and regulations apply such that the DNO or its affiliated businesses cannot perform any DSO related functions or activities. In practice, it requires full separation of assets, staff, as well as technical and financial resources. It also requires, as Ofgem noted for the potential full separation of ESO from National Grid, potentially significant changes to the legislative framework, licensing requirements as well as industry codes and procedures.60

Ownership unbundling in the DNO-DSO context could result in a range of options in terms of number of DSOs resulting from the restructuring of the sector from 14 DSOs (one for each DNO licence area) down to a single national DSO. In the remainder of this report, we assume ownership separation results in the creation of six fully independent DSOs reflecting the current structure of the DNO sector. This assumes each DSO would continue to be responsible for the system operation of the geographical areas covered by its current DNO licensees within the group, albeit as a fully separate corporate entity. An analysis of the different possible ownership models for the DSO goes beyond the scope of this report.

### 3.2.5. ESO amalgamation

While the options listed above represent different degrees of vertical integration between the DNO and DSO activities, a further option is to integrate some or all of the DSO functions with the national ESO.

Hence, the additional ESO amalgamation option means full ownership unbundling of the DSO from the DNO and consolidation of all DSO functions into National Grid ESO. We assume in the remainder of the report, that this would result in the DSO function being divested from the DNO group and fully merged through acquisition into National Grid ESO.

### 3.3. Degree of Functional Separation

As well as the choice regarding the degree of vertical separation between the DNO and DSO activities (and possibly whether to integrate the ESO and DSO activities), a further choice is required as to which of the activities currently performed by the integrated DNO should be allocated to the DSO. In its recent joint consultation document, BEIS and Ofgem have noted

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60 Ofgem (25 January 2021), Review of GB energy System Operation, p. 95.
that they may consider different levels of “functional separation” of the three DSO roles (planning, operation and market facilitation) or even elements within these functions.\(^6\)

Based on our review of materials and working documents published by Ofgem and DNOs about the DSO roles and functions, as well as discussions with SSE experts, we consider four alternative levels of functional separation of the DSO function, which differ according to the range of functions performed by the DSO from narrow, to wider and widest.

### 3.3.1. Narrow DSO separation

Under a Narrow arrangement the DSO would be solely responsible for the market and commercial arrangements associated with securing flexibility, communicating system requirements and recording data in relation to flexibility requirements. Table 3.1 provides an overview of the functions and activities that we assume would be performed by the DSO under the Narrow option.

**Table 3.1: Overview of Narrow DSO Functions and Activities**

<table>
<thead>
<tr>
<th>Functions</th>
<th>Activities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Communicate system requirements</td>
<td>• Signposting system requirements</td>
</tr>
<tr>
<td></td>
<td>• Engaging with market and encouraging participation</td>
</tr>
<tr>
<td></td>
<td>• Coordinating with platforms or intermediaries to promote system requirements</td>
</tr>
<tr>
<td>Forecasting system requirements (network and flexibility)</td>
<td>• To build a picture of the network but not evaluating solutions.</td>
</tr>
<tr>
<td></td>
<td>• Underlying network models remain within the DNO business.</td>
</tr>
<tr>
<td>Flexibility procurement</td>
<td>• Supporting flexibility providers</td>
</tr>
<tr>
<td></td>
<td>• Helping with processes and dealing with enquiries</td>
</tr>
<tr>
<td></td>
<td>• Overseeing Flexibility Purchase Systems (FPS) and flexibility contracts</td>
</tr>
<tr>
<td>Recording data on flexibility services</td>
<td>• Reviewing external information</td>
</tr>
<tr>
<td></td>
<td>• Responsible for logging the flexibility provider’s performance</td>
</tr>
<tr>
<td></td>
<td>• Rectifying any identified data issues</td>
</tr>
<tr>
<td></td>
<td>• Audit processes</td>
</tr>
<tr>
<td>Market engagement and development</td>
<td>• Designing new services ready for commercial assessment</td>
</tr>
<tr>
<td></td>
<td>• Coordinating collaboration across internal teams (Billing, Policy, Legal)</td>
</tr>
<tr>
<td></td>
<td>• Building work instructions</td>
</tr>
<tr>
<td></td>
<td>• Policy documents and processes to embed improvements</td>
</tr>
</tbody>
</table>

*Source: NERA analysis.*

### 3.3.2. Wider DSO separation

Under a Wider arrangement the DSO would be responsible for all activities described under the “Narrow” option above, but would also take an active role in evaluating system solutions, by identifying and defining constraints and assessing potential flexibility requirements and identify the most cost-effective solutions from flexibility, asset build or smart options.

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Table 3.2 provides an overview of the functions and activities identified under the Wider DSO option, with the blue, italicised text indicating the functions and activities that are incremental as compared to the narrow DSO definition shown in Table 3.1.

### Table 3.2: Overview of Wider DSO Functions and Activities

<table>
<thead>
<tr>
<th>Functions</th>
<th>Activities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Communicate system requirements</td>
<td>• Signposting system requirements</td>
</tr>
<tr>
<td></td>
<td>• Engaging with market and encouraging participation</td>
</tr>
<tr>
<td></td>
<td>• Coordinating with platforms or intermediaries to promote system requirements</td>
</tr>
<tr>
<td>Forecasting system requirements (network and flexibility)</td>
<td>• To build a picture of the network but not evaluating solutions.</td>
</tr>
<tr>
<td></td>
<td>• Underlying network models remain within the DNO business.</td>
</tr>
<tr>
<td>Evaluating system solutions</td>
<td>• Identifying and defining constraints</td>
</tr>
<tr>
<td></td>
<td>• Assessing potential flexibility requirements and publishing a Distribution Network Options Assessment (DNOA)</td>
</tr>
<tr>
<td></td>
<td>• assessing the most efficient and cost-effective solutions from flexibility, asset build or smart solutions.</td>
</tr>
<tr>
<td>Flexibility procurement</td>
<td>• Supporting flexibility providers</td>
</tr>
<tr>
<td></td>
<td>• Helping with processes and dealing with enquiries</td>
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<tr>
<td></td>
<td>• Overseeing Flexibility Purchase Systems (FPS) and flexibility contracts</td>
</tr>
<tr>
<td>Recording data on flexibility services</td>
<td>• Reviewing external information</td>
</tr>
<tr>
<td></td>
<td>• Responsible for logging the flexibility provider’s performance</td>
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<tr>
<td></td>
<td>• Rectifying any identified data issues</td>
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<tr>
<td></td>
<td>• Audit processes</td>
</tr>
<tr>
<td>Market engagement and development</td>
<td>• Designing new services ready for commercial assessment</td>
</tr>
<tr>
<td></td>
<td>• Coordinating collaboration across internal teams (Billing, Policy, Legal)</td>
</tr>
<tr>
<td></td>
<td>• Building work instructions</td>
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<tr>
<td></td>
<td>• Policy documents and processes to embed improvements</td>
</tr>
</tbody>
</table>

*Note: Blue text indicates additional function or activity relative to the Narrow DSO option. Source: NERA analysis.*

### 3.3.3. Widest DSO separation

Under the Widest DSO separation option, the DSO would be responsible for all network planning, operation and market facilitation functions that can be identified. In practice, the DSO would be responsible for all activities described above, including also managing and dispatching operational flexibility as well as having responsibility for Distribution Use of System (DuoS) charging and settlement.

Table 3.3 provides an overview of the functions and activities identified under the Widest DSO option. As before, the blue, italicised text indicates the functions and activities that are incremental as compared to the wider DSO definition shown in Table 3.2.
Table 3.3: Overview of Widest DSO Functions and Activities

<table>
<thead>
<tr>
<th>Functions</th>
<th>Activities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Communicate system requirements</td>
<td>• Signposting system requirements</td>
</tr>
<tr>
<td></td>
<td>• Engaging with market and encouraging participation</td>
</tr>
<tr>
<td></td>
<td>• Coordinating with platforms or intermediaries to promote system requirements</td>
</tr>
<tr>
<td>Forecasting system requirements (network and flexibility)</td>
<td>• To build a picture of the network but not evaluating solutions.</td>
</tr>
<tr>
<td></td>
<td>• Underlying network models remain within the DNO business.</td>
</tr>
<tr>
<td>Evaluating system solutions</td>
<td>• Identifying and defining constraints</td>
</tr>
<tr>
<td></td>
<td>• Assessing potential flexibility requirements and publishing a Distribution Network Options Assessment (DNOA)</td>
</tr>
<tr>
<td></td>
<td>• Assessing the most efficient and cost-effective solutions from flexibility, asset build or smart solutions.</td>
</tr>
<tr>
<td>Flexibility procurement</td>
<td>• <em>Full responsibility</em> for supporting flexibility providers</td>
</tr>
<tr>
<td></td>
<td>• Helping with processes and dealing with enquiries</td>
</tr>
<tr>
<td></td>
<td>• Overseeing Flexibility Purchase Systems (FPS) and flexibility contracts</td>
</tr>
<tr>
<td>Recording data on flexibility services</td>
<td>• Reviewing external information</td>
</tr>
<tr>
<td></td>
<td>• Responsible for logging the flexibility provider’s performance</td>
</tr>
<tr>
<td></td>
<td>• Rectifying any identified data issues</td>
</tr>
<tr>
<td></td>
<td>• Audit processes</td>
</tr>
<tr>
<td>Managing and dispatching operational flexibility</td>
<td>• Managing and scheduling the dispatch of flexibility alongside our other network solutions</td>
</tr>
<tr>
<td></td>
<td>• Defining the priority of the options</td>
</tr>
<tr>
<td></td>
<td>• Instigating the Constraint Management Zones (CMZs)</td>
</tr>
<tr>
<td></td>
<td>• Responsible for dealing with N-1 events and dispatching flex for real-time issues</td>
</tr>
<tr>
<td></td>
<td>• Leading coordination with the ESO (and other parties).</td>
</tr>
<tr>
<td>Market engagement and development</td>
<td>• Designing new services ready for commercial assessment</td>
</tr>
<tr>
<td></td>
<td>• Coordinating collaboration across internal teams (Billing, Policy, Legal)</td>
</tr>
<tr>
<td></td>
<td>• <em>Focusing on the technical requirements and policy needs for flexibility</em></td>
</tr>
<tr>
<td></td>
<td>• Building work instructions</td>
</tr>
<tr>
<td></td>
<td>• Policy documents and processes to embed improvements</td>
</tr>
<tr>
<td>Responsible for charging and settlement</td>
<td>• <em>Full responsibility of charging Distribution Use of System (DuoS) charges and settlement.</em></td>
</tr>
</tbody>
</table>

Note: Blue text indicates additional function or activity relative to the Wider DSO option.
Source: NERA analysis.

3.4. Summary of Options to be Evaluated

Based on the above, and as Figure 3.2 shows below, we have identified nine possible alternative options for DSO governance models based on:
The level of business separation, ranging from light separation under ring-fencing arrangements, to legal and full ownership separation, as well as consolidation of the DSO within the ESO.

The level of functional separation, ranging from a narrowly defined DSO (“Narrow”) which performs only a subset of the three functions identified by Ofgem of planning, operation and market facilitation, to a widely defined DSO (“Widest”) which performs all three functions.

We do not consider the case for any form of business separation beyond ring-fencing in combination with the narrow functional definition of the DSO activities. We take this approach because we assume that the high costs of implementing more stringent business separation options would not be justifiable for this very limited range of activities performed currently by the integrated DSO-DNO business.

**Figure 3.2: Overview of Candidate DSO Governance Models**

![Diagram showing the levels of business and functional separation for DSO and DNO activities.](Source: NERA illustration)
4. The Potential Benefits from DSO Separation for Customers

As explained in Section 2.3 above, a possible benefit from separation of the DSO and DNO arises from the avoidance of conflicts of interest, and in particular the incentive that the integrated company might have to favour the development of asset-based solutions provided by its DNO business unit, over alternatives such as flexibility solutions that could be provided by third parties that are contracted to the DSO business unit.

This chapter examines the theoretical foundations for any concerns about such conflicts of interest, assesses to what extent such conflicts are likely to have real, detrimental effects to economic efficiency in the context of an integrated DNO-DSO, and assesses the benefits of the separation options outlined above with some quantification of their possible scale.

4.1. Trade-offs between Asset and Non-asset Solutions

4.1.1. Trade-offs exist between “asset solutions” delivered by the DNO and alternatives provided by DERs

DNOs have historically been responsible for expanding, maintaining and operating the distribution networks in their service areas, balancing delivery of service at the least possible cost against providing appropriate levels of service to customers.

The services provided by the DNO include the provisions of new connections to the network, the provision of network capacity to ensure that growth in demand for the network from demand or generation can be served, and maintaining or improving the reliability of the system, including ensuring its resilience to major incidents like storms, and meeting public policy and legislative objectives such as environmental requirements.

Until recently, the main way in which DNOs provided these services has been through their own operational activities (e.g., maintenance, fault restoration capability, and vegetation management) and capital investments (e.g., replacement and reinforcement of the network). These operational activities and capital investments have been traditionally either directly performed by the DNOs themselves or procured by third parties through tender processes. However, technological change in the electricity industry means this traditional model of providing such services may not always be the least-cost means of service delivery:

- **Digitalisation** allows for more active management of the demand-side than was possible in the past, so it may be more efficient for some customers to adjust their demand for electricity to reduce network capacity requirements, than for the DNO to expand network capacity;

- **Decentralisation** also means that generators are increasingly connecting to the power grid at distribution voltages, and the costs of electricity storage are falling. These trends create more possibilities for third party DERs to adjust their power import from and/or export to distribution systems to reduce the need for DNOs to invest in network infrastructure to provide the required network capacity. DERs also have the potential to be used for other services, like helping the DNO to maintain network capacity requirements despite delays in commissioning new distribution infrastructure, or helping DNOs improve reliability of supply by providing a back-up in case of problems with the network; and
Decarbonisation is increasing the requirements for distribution network capacity, which will require substantial investments to support growth in renewables and electrification of heating and transport load. These requirements for network capacity can be delivered through investments in the physical network or by contracting with third party DERs.

4.1.2. DNOs face choices between asset solutions and DERs; and there is a perceived risk they favour asset solutions they deliver

The changes in technology discussed above alter the role of the DNO:

- Over the planning horizon, a DNO faces new trade-offs between (i) developing assets itself or providing its own operational solutions to improve/maintain reliability and network capacity, and (ii) contracting with third parties to procure services that enable the DNO to provide the same (or similar) services to customers.
- And, once services from third parties are procured, the DNO will need to develop new capabilities to dispatch them in real time (possibly alongside the real time use of automation in its own network). As this role expands, the distribution system will no longer be a relatively passive network asset, but will need to be operated in real time to ensure the continuity of supply to customers and the safe operation of the network.

Because of the trade-off between DERs and asset solutions provided by the DNO, there is a risk that DNOs (if integrated with the DSO responsible for network planning decisions) could favour solutions provided by its DNO business, over solutions provided by third parties. There is also a risk that an integrated DNO and DSO business could have informational advantages over competing providers of services. And, in cases where DNOs are affiliated with DER businesses, there is also a risk the DNO could favour the DER assets of its affiliates when taking real time operational decisions, such as regards to dispatch or the curtailment of network capacity to DERs without a firm connection.

There is therefore at least a potential or perceived risk of the DNO favouring asset solutions and/or affiliated companies in its planning and operational decisions, and a risk that the DNO has informational advantages compared to DERs (where this cannot be mitigated through transparency measures, as we discuss further in Section 4.3.6 below). These risks may create costs for customers, as they may cause the DNO to reject economically efficient DER solutions provided by third parties, in favour of alternatives offered by the DNO itself and/or its affiliates.

4.2. The Benefits of Separating the ESO from other National Grid Companies were Unevidenced Assumptions

4.2.1. There were similar discussions about the risk of asset ownership bias prior to ESO separation

Similar potential benefits of separation were considered by Ofgem and BEIS in the debate over whether to separate the system operator from transmission ownership at the transmission level, which has led to the Electricity System Operator (ESO) being legally separated from National Grid’s other businesses, in particular its Transmission Owner (TO) activities.

At the transmission level, National Grid’s integrated transmission business had previously been responsible for owning, developing and maintaining the transmission network in
England and Wales, while also acting as the System Operator for the whole of Great Britain. The SO role, which is now performed by the ESO business, requires it to operate the system in real time, operate the balancing and ancillary service markets and perform other activities like long-term network planning, researching how to accommodate new technologies, energy demand forecasting, and supporting competition in networks.62

4.2.2. The regulatory framework identified the TO and SO functions separately a long time before the creation of the ESO

As discussed in Section 2.2.1 above, these SO responsibilities had been in operation for some time within National Grid, as balancing and ancillary services have been an integral part of the English and Welsh electricity market since privatisation. Hence, the activities now performed by the ESO (unlike the nascent DSO activities within the DNO businesses) were long-established functions by the time of ESO separation in 2019.

Also, as mentioned in Section 2.2.1 above, while National Grid has performed the SO functions across Great Britain since 2005 when BETTA was introduced,63 it is also the TO in England and Wales. Given these dual roles, Ofgem had been identifying the costs and activities of the SO separately for a long time before the ESO separation in 2019.64

The relationship between the TOs and the SO had in fact been detailed in the System Operator Transmission Owner Code (STC), originally introduced in 2004.65 Ofgem had also designed schemes to incentivise the SO to operate efficiently and economically since the introduction of the New Electricity Trading Arrangements (NETA) in 2001, as part of the SO price control that was set separately from the price control for National Grid’s TO business.66

4.2.3. FTI’s quantification strategy relies on arbitrary assumptions and instructions from Ofgem

The potential asset ownership bias in transmission arises for several reasons. In the Cost Benefit Analysis (CBA) of ESO separation commissioned by Ofgem, FTI suggests that the SO may favour the solutions offered by its TO over other TOs that can provide similar services, distorting competition.67 The SO may also advocate more investment than necessary to increase its Regulatory Asset Value (RAV), and not make efficient use of

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62 National Grid plc’s structure for gas transmission is different. While in electricity the NG ESO is already a legally separated entity from NGET, in gas the system operator is fully integrated within National Grid Gas Transmission.

63 Ofgem & DTI (4 February 2005), BETTA User Guide: A summary of the new British Electricity Trading and Transmission Arrangements (BETTA) and a high-level guide to the key activities required to implement the new arrangements and run-off the pre-BETTA arrangements, p. 7.

64 For instance, National Grid plc claims in its Annual Report and Accounts 2011/12 to “operate under eight price controls in the UK, comprising two for our UK electricity transmission operations, one covering our role as transmission owner (TO) and the other for our role as system operator (SO); two for our gas transmission operations, again one as TO and one as SO; and one for each of our four regional gas distribution networks”. Source: National Grid plc (2012), Annual Report and Accounts, p. 25.

65 DTI (1 September 2004), British Electricity Trading and Transmission Arrangements Approval of form of STC (System Operator – Transmission Owner Code) Framework Agreement.

66 Ofgem (27 September 2000), The transmission price control review of the National Grid Company from 2001 Transmission asset owner - Final proposals, p. 3.

balancing market solutions to relieve congestion and manage voltage.\textsuperscript{68} It may also recommend technologies that create more demand for transmission over others that are equally (or more) efficient.\textsuperscript{69}

The detrimental effects of these biases are not readily quantifiable, so FTI assumes that “removing the potential conflicts identified above requires a full unbundling of the SO from the TO”.\textsuperscript{70} It relies on instructions from Ofgem on what to assume regarding the scale of these effects:

\begin{itemize}
  \item To estimate the benefits from removing conflicts of interest, Ofgem instructed FTI to assume that full separation reduces expenditure by between 1 per cent and 10 per cent of totex.\textsuperscript{71}
  \item To estimate the benefits from the removal of biases in competitive procurement, FTI first identifies the value of the transmission assets that could be procured through a competitive process. It then assumes cost savings for these projects from competitive procurement of between 11 per cent and 20 per cent, as compared to the initial estimated cost.\textsuperscript{72} Further, Ofgem instructed FTI to assume that between 25 per cent and 50 per cent of such savings would be achieved through full separation.
\end{itemize}

Hence, the assumptions on the scale of benefits from separation are based on instructions from Ofgem, not any tangible analysis or evidence.

The lack of evidence for tangible benefits arising from separation does not invalidate the CBA exercise performed to justify ESO separation. Indeed, it is common for qualitative costs and benefits of a policy intervention to be factored into policy appraisal, and the HMT Green Book also suggests the use of “switching values” to identify the value that a key input variable would need to take in order to change a policy recommendation.\textsuperscript{73}

Hence, this assumed benefit of ESO separation provides a natural starting point for assessing the potential benefits of DSO separation, to be weighed against the costs of separation discussed in Chapter 5. In the remainder of this chapter we assess the likely extent of these benefits of DSO separation, and consider their likely size relative to the benefits of ESO separation.

\textsuperscript{68} FTI (January 2021), GB System Operator Review: report prepared for Ofgem, p. 6.
\textsuperscript{69} FTI (January 2021), GB System Operator Review: report prepared for Ofgem, p. 6.
\textsuperscript{70} FTI (January 2021), GB System Operator Review: report prepared for Ofgem, p. 38.
\textsuperscript{71} FTI (January 2021), GB System Operator Review: report prepared for Ofgem, p. 45.
4.3. **Financial Incentives to Expand the DNO Business and Potential Mitigants**

4.3.1. **The theory and practice of economic regulation suggests DNOs may have incentives to favour solutions they deliver themselves**

Regulatory economics literature shows utilities can have incentives to gold plate their network. The “Averch-Johnson effect” refers to the tendency of regulated firms to accumulate excessive capital to increase their profits, in cases where the company’s profits are proportional to the capital deployed within the network. This incentive would lead DNOs to favour capital-intensive solutions over other solutions that are cheaper and perhaps more efficient – whether they are operational solutions they deliver themselves or solutions provided by third parties – as RAV growth increases the value of the business.\(^{74}\)

In practice, this incentive may exist when the allowed rate of return provided to DNOs on their RAV over the life of an investment exceeds the opportunity cost of capital of their investors. Recent market evidence suggests that utilities are sold at a premium to RAV, suggesting RAV growth may increase the value of the business in practice. Such evidence (amongst other things) informed the Competition and Markets Authority’s (CMA) final determination for the RIIO-2 price control appeals in favour of Ofgem’s decision to reduce the cost of equity.\(^{75}\) However, this effect can also be managed through the regulator setting an allowed return on capital that reflects the opportunity cost of capital as closely as possible; Ofgem’s recent RIIO-2 decision to reduce the allowed Cost of Equity (if replicated at RIIO-ED2) reduces the value of capital invested in distribution business.

In addition to this incentive to gold plate the network through capital expenditure, owners of the distribution business may also be able to increase its value by increasing the scale of its own operational activities. For instance, the model of “incentive regulation” used in the UK to set utilities’ allowances involves setting allowances for all categories of expenditure based on cost forecasts, to create an incentive (through a “sharing factor”) to reduce companies’ actual costs. As such, there will be a tendency for higher levels of both operational and capital expenditure to result in greater opportunities to outperform the price controls, which also increases value for shareholders.

Hence, increasing both asset value and operational expenditure incurred by the DNO itself can create opportunities for value creation. As such, at least in theory, DNOs may have an incentive to favour solutions delivered themselves to the solutions provided by third parties.

4.3.2. **Design of the price control framework provides some mitigation of the incentive for DNOs to favour their own solutions**

However, the design of the price control framework for electricity distribution in Great Britain has (at least to some extent) sought to address this tendency for DNOs to favour their own solutions above those delivered by third party DER providers:

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• The totex incentive, discussed further in Section 4.3.3 below, plays an important role in equalising DNOs’ financial incentives within the control period across all categories of expenditure, including payments to third party flexibility providers.

• The RIIO cost assessment process scrutinises DNOs’ business plan capex projections in detail, so that Ofgem will only release funding for capex when it is well-justified. Specifically, DNOs must provide evidence that both justifies projections of anticipated demand and the efficiency of the proposed solution. The cost-assessment in RIIO-ED2 will not just prioritise technology neutrality (limiting the opex-capex trade-off), but will also make sure that the implemented solution does not hinder the achievement of the net zero targets. However, Ofgem’s ability to scrutinise DNOs’ capex plans may be limited by an asymmetric information problem, whereby it may not be able to tell whether DNOs’ long-term plans include an excessive expansion of distribution systems. Whilst this may be an issue today, the information asymmetry problem may become less relevant in the future as DNOs will publish more data through the Open Networks project and which will allow third parties, including Ofgem, to fully scrutinise the plans and assumptions made by the DNO (see Section 4.3.6 below).

• DNOs have incentives to put forward well-justified business plans through the Business Plan incentive (BPI). Under the BPI, Ofgem assesses the DNOs’ business plans and gives them a reward or a penalty based on its evaluation of the plans from both a qualitative and cost assessment perspective. Throughout the regulatory price control review, there is further oversight and scrutiny of DNOs’ capex plans by Customer Engagement Groups (CEGs), Government and Local Authorities, the RIIO-2 Challenge Group, and interested parties who may be adversely affected by price control decisions also have the right of appeal of price control decisions to the CMA.

However, we also acknowledge (see Section 4.3.7 below) that these mechanisms may not comprehensively eliminate the incentive and ability for DNOs to favour solutions developed by their networks over services provided by third party DER providers.

4.3.3. The use of totex incentives provides an important mitigant to DNOs’ incentives to favour asset solutions over DERs

The totex incentive seeks to encourage DNOs to make a least-cost trade-off between all categories of their opex and capex within the price control period, so that an operating expense (like payments to a DER) is treated in the same way as a capital expense. The Totex Incentive Mechanism (TIM), which apportions savings or increased costs relative to

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76 Ofgem (17 December 2020), RIIO-ED2 Sector Specific Methodology Decision: Overview, p. 36-37.


78 See, for example: CMA (28 October 2021), Final Determination: Volume 2B: Joined Grounds B, C and D, p. 59.


80 Flexibility payments are included in the RRP as primary and secondary reinforcement costs, which therefore fall into the load-related capex. Ofgem, however, considers flexibility as an opex solution. Source: Ofgem (August 2019), Links with procurement of flexibility – discussion note, p. 12.
the allowance set at the price control review between consumers and investors, is designed to provide a strong incentive for companies to operate efficiently.\textsuperscript{81}

The TIM treats all categories of totex in the same way, so that if a DNO spends £1 above its target, it bears the same share of this additional £1 of expenditure irrespective of the cost category in which it is incurred. It achieves this by applying a common sharing factor to all categories of costs, and a fixed capitalisation rate, such that the same proportion of DNOs’ expenditure enters the RAV, irrespective of the actual ratio between operating and capital costs. The TIM therefore seeks to remove any incentive to favour capital over operational expenses, or to favour DNO-provided solutions over flexibility contracts.

Indeed, within the control period, DNOs may have an \textit{excessive} incentive to deliver flexibility solutions (which we further discuss in Section 4.3.4 below) over capital solutions. For example:

- Consider the case of an increase in demand that the DNO can accommodate either with a £100 capex investment lasting 40 years or with a £10/year 5-year flexibility contract.
- Evaluating the two options with a very simplistic approach,\textsuperscript{82} the capex solution would imply annual costs of £5.83 and the flexibility service of £10.
- While this capex solution may be preferable (least-cost) in the long term if the demand increase is permanent, \textit{within the price control} the DNO is incentivised to choose the flexibility contract. Using flexibility allows the DNO to make £50 of savings in the current control period and retain part of these savings through the TIM.

DNOs’ investment decisions made in response to the TIM within a control period are also unlikely to consider the benefits that come from developing network capacity ahead of need. Investment ahead of a clear need may be wasteful, due to the risk of stranded assets. But in some situations where demand growth is likely, investing in large assets before demand has materialised may: (1) speed up connection times for low carbon technologies, and therefore speed up the transition to net zero, and (2) achieve economies of scale such as from the avoided cost of upgrading the same piece of network multiple times, which also reduces disruption for wider society (i.e., fewer roadworks).

Other aspects of the regulatory framework may also provide inadequate incentives to deploy capital solutions. Notably, DNOs also have little incentive to consider the “incremental costs” incurred to provide investments that deliver outputs to the wider power system. A good example is losses, where it may be economically efficient for DNOs to oversize circuit capacity to reduce losses, or incur extra costs for low loss transformers. However, the RIIO-ED1 framework provides no economic incentive for DNOs to make such investments.

Hence, in conclusion:

- The TIM ensures DNOs have no incentive to over-invest in their networks during the price control period by making too little use of DERs; and

\textsuperscript{81} Ofgem (30 July 2020), RIIO-ED2 Sector Specific Methodology Consultation: Overview, p. 8.

\textsuperscript{82} We performed an annuity calculation using a 5 per cent real cost of capital, recovering £100 over 40 years.
• Even if DNOs were to advocate for funding to increase the value of their RAVs there are other types of investment they could make that would not substitute inefficiently for flexibility.

4.3.4. The emergence of a flexibility market provides a mechanism for avoiding excessive reinforcement

While the regulatory framework seeks to equalise incentives to deliver DNO opex/capex solutions vs. solutions provided by third party DERs, another key enabler for achieving the efficient balance between these options is the emergence of a market for flexibility products.

A flexibility contract is essentially a call option. It is an agreement between the DNO and a DER provider in which the provider gives the DNO an option to call upon the flexibility provider to adjust its consumption or production of electricity. The contract specifies technical parameters, such as the notice provided to the DER before its flexibility is called upon, the amount by which it is expected to adjust consumption or production, and for how long and how often it can be asked to do so. In return, the flexibility provider receives a guaranteed payment for their availability (i.e., an option fee) and a fee when the flexibility provider is called upon (i.e., an exercise fee).

The reform of the DNOs’ planning standard through the replacement of Engineering Recommendation P2/6 with P2/7 has also allowed DNOs to make more use of flexibility products in their network planning decisions. Engineering Recommendation P2/7 constrains DNOs to ensure a minimum level of security of supply to consumers. Building on P2/6, which considered asset redundancy (with some limited provision to the use of embedded generation), the revised standard gives DNOs additional flexibility to harness the benefits provided by DERs in providing security of supply. Specifically, when evaluating the security requirements of a system, DNOs can now consider the contribution from network assets as well as Distributed Generation (DG), demand facilities with Demand Side Response (DSR) schemes and Electricity Storage (ES) connected to the network.83

The emergence of a market for flexibility products brings a number of benefits that will enable a more efficient trade-off between DNO and DER solutions:

• Without flexibility contracts, there would be no contractual mechanism that allows DER providers to realise a revenue stream commensurate with the benefits they provide to the DNO in terms of avoided or deferred capex and/or opex. As such, DERs could not be incentivised to provide an economically efficient level of service to the DNO (i.e., support to the DNO at the time and part of the grid where it can help the DNO avoid other costs).
  – Indeed, DERs would still have connected at distribution voltages and their penetration would likely still have risen materially, as they seek to participate in national energy, capacity and ancillary service markets, and DER technology improves.
  – However, they would not have had an incentive to consider the impact of their locational decisions and import/export patterns on distribution costs, except to the limited extent these are signaled through DuoS charges. Flexibility contracts provide a much more targeted commercial signal than DuoS charges, and they provide the

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DER investor with a contractual guarantee of future payments from the DNO, whereas DuoS charges may change from year-to-year.

- The emergence of flexibility markets allows the DNO to obtain real, market evidence on the costs of DER procurement, which it would only be able to estimate itself. This transparent market evidence allows the DNO to make a trade-off between the costs it would incur itself to provide asset solutions, against the costs it would face to pay DER providers to provide the services needed to avoid such costs.

- By developing platforms and standardised contracts for the procurement of flexibility, DNOs can reduce the costs they incur to procure services from DERs, and improve awareness and understanding of flexibility products amongst potential DER developers. These developments will tend to reduce the transactions costs associated with procuring DERs in the future, attract more DER participants, and therefore improve the liquidity of the market from which DNOs procure services.

- Although the market for flexibility is relatively new, it has been growing quickly over the past few years, increasing the potential to achieve the benefits described above. Figures from the Energy Networks Association (ENA) show that between January and July 2021, over 1,609MW of flexibility contracts have been procured. This represents a 1,285 per cent increase from the 116MW procured in 2018.84

Related to the flexibility market, DNOs are increasingly offering Active Network Management (ANM) to facilitate flexible generation connections to their systems,85 allowing connecting generators to make a trade-off between the higher capital costs associated with obtaining a “firm” connection to the grid, against a cheaper “non-firm” connection that may sometimes be curtailed.86 This is another mechanism DNOs use to harness DERs’ willingness to be flexible in their import/export patterns, to avoid operating and capital expenditure by the DNO.

4.3.5. The flexibility market is still developing under the existing integrated DNO-DSO model

Given flexibility is a relatively new tool available to DNOs, it is of course possible that its use could still be improved. DNOs have been procuring local flexibility since 2018 only, and consequently the market is still relatively young and not well-developed. The recent development of a Common Evaluation Methodology (CEM) tool increases the degree of transparency of the tendering process by providing a standardised method to evaluate options to manage the network. The ENA is also trying to support the flexibility market by designing a version of a common contract by April 2023.87

84 Data retrieved from “ON21-WS1A-Flexibility Figures 2021 Full Update (30 Jul 2021)”.
86 Ofgem’s Access SCR aims to ensure efficient and flexible use of electricity networks and to benefit customers from new technologies and services. Subject to the final decision, expected in late 2021, Ofgem proposes to implement the access rights and connection boundary reforms by April 2023. Source: Ofgem (30 June 2021), Access and Forward-looking Charges Significant Code Review: Consultation on Minded to Positions, p. 26.
The fact that DNOs’ use of flexibility could be expanded and improved is not surprising, as this is a nascent market. Unlike the SO at the transmission level which has procured operational services for decades now, technological change has only relatively recently created a need for flexibility contracts to take advantage of the improving economics of DERs. Hence, it is not surprising that there is still scope for improvement in the use of flexibility services.

It also remains unclear how large the potential for flexibility will be in offsetting the need for distribution capex. There is a theoretical potential to avoid distribution reinforcements that comes from having a more active demand side (see Section 4.1). This could arise through customers’ using smart appliances to shift load, smart EV charging, embedded storage, etc. For example, a scenario analysis by Imperial College tries to quantify the benefits of integrating new sources of flexibility in a system with carbon emissions of 100g CO2/kWh by 2030. The study finds that reduced requirements for reinforcement in the distribution network account for 10-20 per cent of the £3.2bn-£4.7bn/year of total savings the study identifies.\(^88\)

However, it remains highly uncertain whether customers will want to adopt these new technologies or use them in ways that optimise system costs, and even if they do, it may be that they do not provide significant benefits in helping to avoid distribution reinforcements. For example, recent studies show that a combination of high wind penetration in the British wholesale market, combined with a high take-up of smart EV charging would necessitate a very significantly expanded distribution network to enable EV batteries to absorb surplus energy in high wind periods.\(^89\) In other words, smart EV charging may enable highly efficient use of offshore wind resources, but may not avoid the costs of reinforcing the distribution system.

Hence, even if there were an asset ownership bias that deters DNOs from entering into flexibility contracts, in favour of their own solutions, it would be premature to draw conclusions on the extent of its effect since the flexibility market is so nascent.

4.3.6. **Other regulatory mechanisms help ensure DNOs use flexibility markets to make efficient trade-offs with asset solutions**

While the flexibility market has emerged and grown under the current integrated DNO-DSO governance model, there remains a theoretical risk that DNOs might still favour solutions they develop themselves over procuring flexibility services from DERs. For instance, DNOs may face subjective or finely balanced decisions between asset solutions and flexibility procurement. In these circumstances, if DNOs do indeed have incentives to favour asset solutions over those procured from third parties, they may respond to such incentives by favouring their own solutions above those provided by third parties.

However, while this risk exists in theory, Ofgem and DNOs have developed a series of regulatory mechanisms that help to mitigate it:

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\(^88\) Shakoor, A. et al. (May 2017), Roadmap for flexibility services to 2030: A report to the Committee on Climate Change, London: Pöyry, p. 23.

\(^89\) Aunedi, M., et al. (2021), Net-zero GB electricity: cost-optimal generation and storage mix.
• First, the TIM within the RIIO price control remunerates the costs incurred by DNOs to procure flexibility services in the same way as the DNO’s own operating and capital costs. Indeed, as discussed in Section 4.3.3, during the price control period DNOs may even have an exaggerated financial incentive to contract for flexibility over delivering capital solutions.

• The DNOs have committed in December 2018 to the “Flexibility First” approach, coordinated by the Energy Networks Association (ENA). Thus, DNOs have committed to include in their operations smart flexibility services, test the market to compare the traditional network-based solutions to flexibility contracts and work with Ofgem to ensure financial incentives in RIIO-2 do not favour in any way network reinforcement over flexibility.90

• DNOs’ business plans must explain the different options considered for managing network requirements, with CBAs submitted as a minimum requirement of the BPI. To avoid excessive development of the network, Ofgem expects DNOs to fully exploit existing network capacity and flexibility services before building new capacity.91 The CBAs must evaluate all the solutions that were under consideration to meet the network needs. The decision must consider not only the costs and the potential value of the reinforcement deferral, but also other factors such as carbon emissions and societal impacts.92

• A Whole Electricity System Licence Condition, introduced for the first time in 2017, is in place for all electricity network licensees, to encourage cooperation and an efficient management of the system. Ofgem has recently decided to implement a licence modification driven by the recent changes in the industry, effective from 17 May 2021. With respect to data modernisation, Ofgem now imposes some specific data requirements:
  – One licence modification requiring “network licensees to comply with Data Best Practice guidance, this includes requirements data sharing; and another requiring network licensees to publish Digitalisation Strategies and Action Plans”.
  – “Reforms to the Long Term Development Statement (LTDS), which will enhance network planning and investment data”; and
  – The introduction of the Network Development Plan licence condition, requiring “that electricity distributors use all endeavours to prepare and publish a “best view” of the investments needed for the next five-to ten-year period covering the 11kV network and above. This condition requires the publication of the data that underlies this forecast”.93

90 ENA (December 2018), Energy Networks Association’s Flexibility Commitment.
92 Ofgem (8 October 2021), RIIO-ED2 Cost Benefit Analysis (CBA) Guidance.
93 Ofgem (1 April 2021), Decision to implement the Whole Electricity System Licence Condition D17/7A for Transmission Owners and Electricity Distributors, p. 12-13.
Moreover, the Condition 21E (“Procurement and use of distribution flexibility services”) outlines the conditions in which distribution licensees can procure flexibility, ensuring coordination with other parties.94

- Other features of the RIIO regime may also deter DNOs from inflating unnecessarily their expenditure by delivering asset solutions when cheaper flexibility solutions are available:
  - Price Control Deliverables (PCDs) are in place to ensure companies are held accountable to deliver certain outputs. By linking allowances to outputs in RIIO-2, the PCD framework incentivises DNOs to deliver better and more efficient services, without prescribing how they should be achieved (i.e., with network or flexibility solutions).
  - Other incentive schemes such as the Interruptions Incentives Scheme (IIS) are in place to incentivise DNOs to improve or maintain service. Without prescribing what mix of DNO and DSO solutions should be used to do so.

- Finally, the ENA makes DNOs accountable of their decisions by publishing and making transparent the flexibility tender results. Further developments in this direction are underway in 2021 through Workstream 1A of the Open Networks project.95 For example, a Common Evaluation Methodology (CEML) tool, further discussed in Section 4.4.1, allows an objective evaluation of the choice between flexibility solutions and traditional interventions.

4.3.7. The regulatory framework does not fully mitigate incentives to favour asset solutions over procuring flexibility from DERs

Despite the role of the TIM in equalising incentives between all categories of expenditure within the control period, DNOs may still have some possible incentives to expand the network beyond the efficient level of investment. Specifically, DNOs’ capitalisation rate is adjusted at each price control review to reflect the expected balance between operating and capital costs in DNOs’ business plans. Hence, by convincing Ofgem that high levels of capex are required through their business plans, DNOs may be able to inflate their capitalisation rate and achieve higher RAV growth, irrespective of how much totex they actually deliver and the outturn ratio of opex (including flexibility) to capex.

As noted above, DNOs’ ability to exaggerate the need for capex in their business plans is moderated by Ofgem’s cost assessment process, Ofgem’s business plan guidance, the BPI, oversight of the business planning process by CEGs and other regulatory outputs such as PCDs and expected improvements in the data transparency and exchange with the Open Networks project. Hence, DNOs inflating their capex requirements in their business plans, would only have real effect if these mechanisms failed to prevent an exaggerated capex projection.

It follows that while this effect is likely to be limited, it may arise if DNOs have informational advantages that they use to exaggerate the need for capex in a way that cannot be identified through these other “checks and balances”. However, if the DNO does have informational advantages of this kind, it is possible that it would retain these advantages after

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95 ENA (July 2021), Open Networks Project Flexibility Consultation 2021 Overview Version 1, p. 6-7.
separation. It would still be the only party with detailed working knowledge of its own network assets, and both Ofgem and the vertically separated DSO might continue to be at an informational disadvantage (if any such disadvantage exists).

If DNOs were to exhibit a preference for capital over operating expenditure in their business plans in this way, the TIM cannot definitively moderate the incentive DNOs may have to deploy more capital investment and make less use of flexibility solutions than would be economically efficient:

- If DNOs propose a higher share of capital expenditure than would be efficient, DNOs would still have a financial incentive to deliver the lowest-totex combination of flexibility and asset solutions, so it would not actually result in wasteful expenditure unless DNOs’ expenditure decisions within the control period are affected by other factors such as: (1) obligations to deliver specific projects in return for Ofgem providing funding at the price control, or (2) for reputational reasons, i.e. they choose to deliver planned capex despite it not being the least cost solution to ensure their future capex plans are accepted.
  - In principle, both effects (1) and (2) could be mitigated through improvements to the regulatory regime. For instance, Ofgem placing obligations on DNOs to deliver particular levels of capex or particular capex projects or levels of capex (effect 1) is likely to generate inefficiency, as they do not allow DNOs to respond within (relatively long 5-year) control periods to changes in circumstances, so should probably be avoided.
  - Obligations on DNOs to deliver particular levels of capex may also be unnecessary if Ofgem can develop mechanisms to release funding within the control period for capex, as evidence as to the need for it, through re-openers and uncertainty mechanisms. Part of the evidence base for releasing funding may need to be linked to DNOs presenting evidence that they have exhausted the potential for flexibility solutions to address the problem their investments are aimed at mitigating. For instance, in RIIO-ED2, a technologically neutral Strategic Investment volume driver will be in place to support the achievement of net zero targets at lowest cost.96 This would (if effective) address problem (2), as it would encourage an efficient mix of opex and capex spent by DNOs to provide network capacity.

- However, to the extent Ofgem’s oversight of DNOs’ investment choices is influenced by information provided by the DNO, there is a risk that outcomes could be distorted by asymmetry of information between the DNO and Ofgem. Rules that constrain DNOs’ choices between flexibility and capital projects may not be mechanical, or implementable with entirely objective information, detached from the subjective judgment of distribution network planners. There remains a risk, therefore, that Ofgem’s decisions to release funding to DNOs could be influenced by advice or information from DNOs which itself is influenced by the company’s preference for capital schemes over operational alternatives.

4.3.8. **DNOs’ incentives to develop flexibility markets may be limited, if they have a long-term strategic preference for asset solutions**

As noted above, DNOs may need to deliver higher levels of capital expenditure if the supply of flexibility is limited, which in the long-term may increase the value of DNOs’ businesses

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96 Ofgem (17 December 2020), RIIO-ED2 Sector Specific Methodology Decision: Overview, p. 29.
through RAV growth and increase outperformance opportunities. Therefore, DNOs’ may have a limited incentive to promote the long-term development of the flexibility market that would (if successful) increase the supply of competing DERs.

For instance, DNOs could in principle spend money today to encourage DERs within their regions to provide more flexibility. They could proactively work with large energy users in their regions to educate them on how they could enter the flexibility market (or even provide services to the ESO) or spend money to advertise flexibility markets. The RIIO-ED1 framework provides no funding for DNOs to implement such programmes, though RIIO-ED2 may provide incentives or funding for such activities. DNOs may still choose to promote flexibility, but their incentive to do so would be limited, as it would come from increased opportunities to outperform the price control in the next 1 to 5 years, and would be moderated by any long-term preference DNOs have for capital solutions.

However, rather than addressing this problem through business separation, which entails significant costs and risks as explained in Section 5, it may be more efficient for Ofgem to require and fund DNOs to promote flexibility markets. Indeed, some DNOs have put forward “customer value propositions” in their ED2 draft business plans to create an efficient energy system and contribute to the development of flexibility markets as well increase local flexibility market participation.

4.3.9. Differences in regulation mean that any asset ownership bias in distribution will be materially less than in transmission

As described above, while some risk of an asset ownership bias remains for an integrated DNO and DSO, the risks are materially less than they were in transmission when Ofgem assessed the case for SO separation.

The TIM was not used at the transmission level prior to ESO separation. The TOs have never had any ability to capitalise the contractual payments made to third parties to provide services to the grid. These were remunerated through the SO price control largely on a “pass through” basis, with some financial incentive to beat certain cost forecasts.

Hence, while the SO had some incentive to minimise operating costs, it had no incentive to reduce capex. It may also have exhibited a degree of conservatism leading it to prefer assets to operational measures perceived to be less secure. Therefore, the absence of a regulatory mechanism that equalised incentives across operating solutions delivered by third parties and asset solutions means that the SO would not have had an incentive to minimise the joint costs of the two types of solution.

We see evidence of this through empirical work conducted by KPMG to quantify the benefits of implementing totex regulation, to inform the calibration of the PR19 price control in the water sector. KPMG’s work had three elements:

97 NPG (July 2021), Our business plan for 2023-28: a draft for consultation, p. 68.
98 SSEN (July 2021), Powering Communities to net zero Our Draft Business Plan for RIIO-ED2 2023-2028, p. 15.
99 Ofgem (28 November 2011), TPCR4 Rollover: Final Proposals, p. 34-35.
First, KPMG estimated the efficiency benefits of totex regulation by comparing the levels of cost outperformance before and after the introduction of the totex framework.

Second, KPMG analysed the cost changes observed after other major regulatory and structural changes across various infrastructure industries.

Third, KPMG estimated the cost savings achieved through deploying a sample of projects that entailed opex/capex trade-offs, using information provided by water companies.

Unfortunately, there are significant limitations to what lessons we can draw from this research regarding the impact of totex regulation:

- The first approach conflates outperformance of price controls with the benefits of totex regulation, an assumption which is entirely baseless. Price controls may be outperformed for various reasons, including as a result of inaccurate cost forecasting at price control reviews, so outperformance cannot be ascribed to efficiency improvement.

- The second approach considers several structural or regulatory changes (e.g., privatisations or changes of ownership) that neither resemble the unbundling of the DSO from the DNO, nor the introduction of totex regulation, and hence is not a useful comparison either.

However, the third approach in which KPMG reviewed specific evidence on projects that water companies had developed, which would not have been economic without a totex incentive because they entail significant opex/capex trade-offs does provide useful information on the benefits of totex regulation. These projects represent around 3.8 per cent of water companies’ total expenditure in the relevant control period. KPMG identifies that these projects achieved cost savings of 35 per cent, which can be ascribed to the benefits of totex regulation, if they would not have been possible without it.100

KPMG’s analysis under its third approach therefore suggests that the benefits of totex regulation were around 1.3 per cent.101 However, the introduction of totex regulation may have achieved reductions in other cost categories too, as discussed below.

4.4. Managerial Factors within Distribution Businesses

4.4.1. Cultural factors or entrenched practices may tend to favour asset solutions over flexibility

Other features of how DNOs are managed may also affect choices made by the businesses between asset solutions and DERs, beyond the incentives provided to shareholders of DNOs (and hence their senior managers),

For example, it is possible that the culture of the staff, managers, and owners of electricity networks in the UK may push them towards focusing their attention primarily on safety and security of supply. To some extent this is not an undesirable outcome, as the safety of people working on the network and the ability of the network to deliver electricity to customers

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100 KPMG (June 2018), Innovation and efficiency gains from the totex and outcomes framework, p. 70.

101 Assuming no benefits of totex regulation for the expenditure excluded from the sample of projects and calculated as the average totex saving of 35 per cent, multiplied by the 3.8 per cent of expenditure covered by the projects,
should always be a priority. However, a culture of prioritising security of supply may influence the long-term trade-offs DNOs make in their asset planning.

For instance, DNO asset planners may prefer to have control over their ability to meet demand, which they can only do through providing assets themselves. While contracting for flexibility may be cheaper than asset solutions in some circumstances, and may provide security of supply with a high level of reliability, the DNO itself cannot control the availability of a flexibility resource at any moment in time. This may lead to conservatism in network planning and over-investment.

While established practices within DNOs’ planning departments may favour asset solutions, this may be because regulation has until recently required them to do so. Since the development of the new Engineering Recommendation P2/6 network planning standard, DNOs have been able to account for the contribution of embedded generation towards meeting their security standards, but reforms to consider flexibility contracts following the introduction of P2/7 is a relatively recent development. As mentioned in Section 4.3.2, according to the revised standard (P2/7) introduced in 2019, flexibility services such as DSR and storage can contribute to security of supply. Hence, network planners will have limited experience in using DERs in the planning process.

This is compounded by the fact that new DER technologies like batteries are still emerging technologies, the flexibility market itself is still developing, and new CBA methods to compare flexibility with investment options are still relatively new.

For instance, a baseline Common Evaluation Methodology (CEM) tool was only published at the end of 2020, accompanied by its User Guide and several Use Cases. The CEM tool outlines a common strategy DNOs can implement to evaluate flexible vs. non-flexible solutions to meet network needs. All DNOs agreed to start using the CEM starting from 1 April 2021.102

Hence, on a practical level, it may take some time for DNOs to adjust to new planning practices, and DNOs will need to address this challenge to avoid inefficient investment in the coming years as electrification requires significant growth in network capacity.

However, this challenge facing DNOs exists regardless from the governance structure of the DNO/DSO and would not be made easier through business separation. A separated DSO would still have strong reputational incentives to ensure security of supply, and it would still employ asset planners who may be inclined to follow traditional network planning practices.

4.4.2. Incentives to promote asset-based solutions through management incentive schemes

DNO employees may also have incentives to increase the value of the company they work for, if they own shares of the company (e.g., some DNOs are part of listed companies, so employees may have shareholdings in the company). Such an incentive may further

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102 ENA (8 April 2021), Common Evaluation Methodology and Tool Webinar, p. 7.
incentivise DNOs’ network planners to increase the company’s value by taking decisions to promote asset solutions above those provided by third parties.\textsuperscript{103}

\begin{itemize}
  \item Share incentive schemes may also be used as a corporate governance mechanism to align the incentives of shareholders and senior management.\textsuperscript{104} Indeed, because senior managers can acquire substantial shareholdings in the companies they run, they may have strong incentives to set policies and strategies that promote long-term growth in the business.
  \item Less senior employees may also hold shareholdings in the network company employing them, and such shareholdings may also affect their incentives, but these are likely to be smaller as a share of their total compensation. Hence, any effect of shareholdings on less senior employees’ day-to-day decisions is likely to be less significant, though they could also face indirect incentives to maximise shareholder value to meet objectives set by their managers, and possibly improve their own career prospects and earnings potential.
\end{itemize}

However, while managers within DNOs may have financial incentives to maximise long-term value, especially if they are required to retain shares for several years after their departure from the company, they may also have countervailing incentives to respond to the TIM which promotes the use of flexibility where it can avoid more costly capex. As set out above in Section 4.3.3, DNOs may be able to maximise their short-term earnings within the current control period by using flexibility solutions to a greater extent than would be economically efficient.

4.4.3. **Flexibility may play a role in helping DNOs manage workload**

In the sections above we discuss the role flexibility can play in reducing the need for investment by the DNO to reinforce the network, and the concern that an integrated DNO and DSO may not choose optimally between flexibility and asset solutions. However, flexibility can also play other roles in supporting the DNO’s network operations:

\begin{itemize}
  \item It can allow the DNO to manage workload, such as by enabling faster connections in situations where planning consents or site access are challenging to obtain;
  \item It can allow DNOs to use their resources more efficiently by smoothing out workload to reinforce the network over time, which may become an increasingly important role for flexibility contracts as reinforcement requirements rise due to electrification; and
  \item It may also allow DNOs to avoid or replace condition-related work or improve their performance under the IIS.
\end{itemize}

In all these cases, the DNO needs to decide whether to enter into flexibility contracts by making complex trade-offs between payments to flexibility providers and the costs incurred in its own operations. If the DSO were separated from the DNO and the DSO were


\textsuperscript{104} In Mehran, H. (1992), Executive Incentive Plans, Corporate Control, and Capital Structure, *Journal of Financial and Quantitative Analysis*, 27(4): 539-560, the author finds that incentives schemes and the amount of stocks owned by managers increase the firm’s leverage ratio.
responsible for flexibility procurement decisions, it may not be able to consider these effects as comprehensively or thoroughly as an integrated DNO-DSO.\textsuperscript{105}

4.5. Potential Bias Against Competitively Tendered Network Investments

OFGEM is developing a system called “early competition”, whereby large DNO projects with a value over £50 million may not be developed by the DNO and funded through the totex allowances, but rather tendered out to allow competition between other providers.

OFGEM’s stated objectives for “early competition” are to “produce benefits for consumers by revealing new or innovative ways of solving network problems (such as network constraints) and avoiding expensive reinforcement costs (for instance, by using flexibility providers or utilising other non-network solutions)”.\textsuperscript{106}

The exact details of the “early competition” system have not been developed yet, although will likely be based on the plan for “early competition” in transmission presented by the National Grid ESO (NGESO). NGESO has recommended a Tender Revenue Stream (TRS) model for early competition.\textsuperscript{107}

If DNOs are responsible for choosing investments and the early competition scheme specifies a value threshold or other criteria for triggering third party procurement, the DNO may have an incentive to select smaller schemes they can deliver and avoid being subject to competition. Hence, an asset ownership bias might push the DNOs to promote smaller projects that can meet the same objectives as larger ones, even if the larger ones would be cheaper, and this might generate inefficiency.

However, this is no more than a theoretical concern:

- The early proposals for the “late competition” scheme are based on the scheme proposed for transmission, whereby “new, separable and high value”\textsuperscript{108} projects can be tendered. However, the schemes for early and late competition in transmission have not yet been implemented, due to delays introducing the relevant regulations. Originally OFGEM pursued the development of the Competitively Appointed Transmission Owner (CATO) model, following the “Extending Competition in Transmission” project in 2015.\textsuperscript{109} The CATO model was intended for both early and late competitions, but development of the model was paused due to legislative delays.\textsuperscript{110} OFGEM then begun development on the

\textsuperscript{105} As discussed in Section 5.2, the costs and time required to engage with the DSO on the need for flexibility contracts may deter the DNO from pursuing the flexibility contract option, and would instead resort to using the more expensive asset-based solutions. It may also provide slower connections or lower levels of reliability due to these costs of interacting between the separated DSO and DNO.


\textsuperscript{107} Note: to implement the plan NGESO assumes the introduction of bespoke legislation and regulatory arrangements. Given the delays in legislation for developing competition models under the previous price control, the need for specific arrangements may present a hurdle to the plan’s introduction. Source: National Grid ESO (April 2021), Early Competition Plan: Onshore electricity transmission, p. 4.

\textsuperscript{108} OFGEM (November 2016), Quick Guide to the CATO Regime, p. 1.

\textsuperscript{109} BEIS (5 July 2021), Impact Assessment: Extending competitive tendering in the GB electricity network, p. 19.

\textsuperscript{110} BEIS (5 July 2021), Impact Assessment: Extending competitive tendering in the GB electricity network, p. 19
Special Purpose Vehicle (SPV) model and considered the use of Competition Proxy Models (CPMs). Currently these models have not been implemented. Initially Ofgem did decide to use the CPM for the Hinkley Seabank project, although later reverted to the RIIO price control arrangements.\(^{111}\)

- At the distribution level the early competition scheme is at an even earlier stage of development, and the case for subjecting DNOs to competition from third party providers of network assets remains unproven. Nonetheless, it is reasonable to assume that the benefits of any early competition scheme would be much lower in distribution than transmission:
  
  - DNOs have much smaller projects than transmission and we understand the number of projects above £50 million has been very limited in the past. For instance, there are only seven High Value Projects (HVPs, valued at more than £25 million) during RIIO-ED1.\(^ {112}\)
  
  - To support the low carbon transition, many of the upgrades that will be needed are at the lower voltages of the distribution system, where individual projects over £50 million are likely to be rare and are less likely to be “new” and “separable” from existing network assets and therefore would not meet the criteria used by Ofgem in identifying transmission projects that could potentially subject to competition schemes. Distribution networks contain many more assets than transmission networks that are significantly smaller in size, and rather than making large discrete investments, DNOs tend to make smaller investments on a continual basis.\(^ {113}\)
  
  - The RIIO-ED2 business plans also show that relatively few distribution projects will qualify for early or late competition, with only one proposed project surpassing the £50 million cost threshold, and no DNO group highlighting a project that meets all criteria.
  
  - In the water sector, where Ofwat has implemented a similar Direct Procurement for Customers (DPC) mechanism, the procurement of third-party investments has been limited to a small number of schemes upstream of the water distribution network.\(^ {114}\)

Hence, there is no reasonable basis for expecting any significant procurement of distribution upgrades from third parties is possible, or even economic. Therefore, unlike at the transmission level, we conclude that the factor “removal of biases in competitive procurement” should be given no weight at all in assessing the case for DSO separation.

### 4.6. Biases between Distribution and Transmission Investments

Decisions by transmission and distribution network operators to provide additional network capacity investments (whether that is through asset solutions or contracts with third parties) are made in response to (or in anticipation of) future growth in demand for network capacity.

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\(^{111}\) Ofgem (22 May 2020), Hinkley-Seabank: Updated decision on delivery model.

\(^{112}\) Ofgem (17 December 2019), Decision on the closeout methodologies for RIIO-ED1, p. 18.


\(^{114}\) Ofwat (November 2020), Direct procurement for customers: Statutory consultation on proposed changes to the conditions of appointment of five water and sewerage companies, p. 5.
The need for network capacity depends in turn on the quantity and location of electricity demand, generation and/or storage.

There are numerous policy uncertainties facing the energy sector, and different decarbonisation pathways may lead to very different needs for transmission and/or distribution network investment. For example, the uncertainty around the role of hydrogen to reach the net zero targets impacts the need for investment in the electricity transmission and distribution networks.

- A large-scale deployment of heat pumps could require substantial distribution reinforcement and growth therefore of distribution systems; whereas

- If hydrogen becomes a prevalent technology for domestic heating as some pathways predict, more transmission might be needed to support bulk renewable generation and green hydrogen production, with less electricity distribution investment.

Although there is significant uncertainty in future transmission and distribution investment requirements, network operators tend to be reactive to requests by customers for connections or observed trends in load growth. For example, new major sources of load and new larger generators may choose to connect at either distribution or transmission voltages, which in turn affects the amount of new network capacity the DNOs need to provide. However, DNOs do not influence this choice:

- Customers and generators will choose which network they connect to, mainly based on the capacity of the plant or the size of their demand. Other factors which customers and generators will consider include prevailing network charges, connection costs, and the speed with which transmission and distribution network operators can provide a connection.

- Transmission and distribution companies do not determine the design of network charges, which are governed by industry codes and regulated by Ofgem, so the investments in response to customers’ connection choices do not require the DNO to make a trade-off between transmission and distribution costs.

As such, any bias DNOs might have towards distribution in favour of transmission network solutions would not have any serious detrimental effect on investments. DNOs can influence the means of providing capacity on their own networks (i.e., asset solutions vs. flexibility – see Section 4.1.1), but they have little (if any) ability to influence whether network capacity is needed.

Also, some measures to mitigate the risk of biases between distribution and transmission investments are already in place. For instance, the Whole Electricity System Licence Condition provides obligations on licensees (DNOs, TOs, and other regulated companies) to collaborate and coordinate in the interest of consumers.115 Licensees are required to promote an efficient and economical operation of the system, for example through data requirements

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115 Ofgem (1 April 2021), Decision to implement the Whole Electricity System Licence Condition D17/7A for Transmission Owners and Electricity Distributors, p. 4.
and reporting requirements such as the maintenance of a Coordination Register. Moreover, Ofgem believes that the Coordinated Adjustment Mechanism (CAM) re-opener:

“will also support DNOs to fulfil their obligations under the proposed new whole electricity system licence condition for RIIO-ED1 electricity licensees concerning cooperation and collaboration, by enabling them to move activities between networks where such collaboration uncovers greater overall consumer value in doing so”.

It follows that the only detrimental impact on the balance between distribution and transmission investments from asset ownership bias by DNOs (if they have any such bias) would come about through very indirect channels. For instance, some government policy decisions affect the need for distribution system investment, and DNOs could conceivably give biased, partial or inaccurate advice to government that leads to policy decisions driving more distribution investments. However, to do so could be reputationally damaging for DNOs, and they are unlikely to provide significantly misleading information.

Likewise, because charging arrangements for transmission and distribution determine customers’ choices to connect at the distribution or transmission level, any bias in these choices primarily arises from inefficiencies in the price signals sent through network charges, not the DNO/DSO governance model.

4.7. Countervailing Incentives Leading to Potential Underinvestment by DNOs

As described above, while we have identified a potential asset ownership bias, that could lead DNOs to promote more use of asset solutions than is economically efficient, there are a number of other reasons why DNOs may in some circumstances favour flexibility over capital solutions, even if capital solutions would be cheaper in the long-term.

As explained above in Section 4.3.3, an important example is the TIM, which rewards the DNOs for reducing their totex by entering flexibility contracts during the price control instead of capex, potentially even in situations where the cheapest long-term solution would be to conduct capital expenditure.

DNOs are facing a very significant requirement to increase the capital expenditure in their grids due to electrification of heating and transport. As the need for network capacity increases, limited human capital and logistical delays mean that DNOs may face resource or other constraints on their ability to deliver the capital required to meet net zero. As explained in Section 4.4, DNOs may use flexibility to ensure they deliver the required network capacity in time to meet consumers’ needs.

The very high requirement for investment also means that any pressure on DNOs from their investors to maximise RAV growth by exaggerating the economic case for network solutions might be mitigated. Even in a relatively low case scenario, the need for distribution

116 Ofgem (1 April 2021), Decision to implement the Whole Electricity System Licence Condition D17/7A for Transmission Owners and Electricity Distributors, p. 12-13, 19.


118 Imperial College & Vivid Economics (April 2019), Accelerated electrification and the GB electricity system Report prepared for Committee on Climate Change, p. 64.
reinforcements in the future is likely to be significant. The need for a significant increase of capex over ED2 compared to the previous price control is evident from the DNOs’ draft business plans. According to the RIIO-2 Challenge Group, load related capital expenditure is forecast to increase by 128 per cent during ED2.119

This means that shareholders’ appetite to achieve RAV growth may be satiated without the need to go beyond the efficient level of investment, as would be the case if DNOs understated the need for flexibility. Indeed, if DNOs face resource constraints, the costs of delivering a marginal capex project may become very high, reducing the incentive to deliver it if the price control framework provides only remuneration for the average costs associated with capex provision. In other words, as capex volumes rise, DNOs’ ability to outperform their price controls may reduce, though of course this depends on how ED2 uncertainty mechanisms are designed which remains uncertain at the time of writing of this report.

4.8. Potential Discrimination in Favour of Affiliated Companies

A DNO is a natural monopoly providing essential network facilities used by all participants in the market. In the terminology widely used in economic literature, it is an “upstream” monopolist. Where the DNO is vertically integrated with its affiliates operating in the competitive “downstream” supply and generation markets, the DNO has a theoretical incentive to foreclose entry by downstream competitors by hindering their ability (or increasing the costs they incur) to access its upstream DNO network. The theory behind this discrimination is that vertically integrated utilities have incentives to discriminate against downstream competitors by setting high charges; unlike potential downstream competitors, the integrated utility can bear the cost of high access charges, because they are transfer payments to its own affiliate.120 By unbundling the network, the incentive to discriminate against rivals is removed, increasing competition in the downstream market.121

In justifying the unbundling of transmission from generation and retail under the third energy package, the EU cited suspected discrimination in favour of subsidiaries.122 The inquiry cited the need for unbundling in order to limit “further risks of discrimination”, resulting in the recommendation of legal unbundling for both transmission and distribution between network actors and all other activities.123 However, the EU considered the issue of discrimination to be less relevant at the distribution level and so mandated lighter unbundling requirements (legal) for distribution relative to transmission.124

Since the third energy package was implemented, localised energy markets at the distribution level especially have evolved, suggesting that the potential discrimination in favour of affiliated companies may be more relevant today than it was in the past. For instance, at least

theoretically, DNOs belonging to a wider group could favour its affiliated DER company in the flexibility procurement market. It could also favour affiliated DERs when providing network access to enable them to access the wholesale market or other system services markets operated by the ESO. This could be done for example through:

- Curtailment of flexible connections, e.g., curtail non-affiliated DERs before affiliated ones when network capacity is constrained;
- Provision of connections more promptly to affiliated businesses than competitors;
- Discrimination in restoration of supply, e.g., providing quicker restoration to affiliated DERs than non-affiliated DERs; or
- Network planning, by creating delays in providing firm grid access to competitors by reinforcing more quickly in areas where affiliated DER projects are planned.

However, in practice there are several strong mitigating factors that suggest that the risk of actual discrimination may be very limited in the distribution sector. These include existing legal separation within groups which prevent the above actions from being performed, and enforcement of competition law which provides for strong penalties both for corporates and individuals failing to comply with such laws.

These established competition rules mean that any benefits from unbundling the DNO from the reduced likelihood of it favouring its affiliated businesses is very low, and should not be given any significant weight in appraising the case for business separation.


Another consideration in assessing the extent of benefits from separation is the degree of market power in very localised energy markets. Conceptually, business separation may help to avoid asset ownership bias through exposing the DNO to competition against third party DER providers, as explained in Section 4.1. If there is a deep and liquid market in the provision of flexibility, this process of competition (administered by a neutral DSO) could generate cost savings for customers.

However, the reinforcements needed to meet customers’ requirements within distribution systems are on a very small scale, and in the case of LV reinforcements it is reasonable to assume that the DNÓ would have a near-monopoly in such a market. For instance, considering DNOs’ historical figures, approximately 87 per cent of the asset additions during RIIO-ED1 were low voltage and only around 12 per cent high voltage (HV and EHV combined). This tendency for the majority of investment requirements to be low voltage highlights the limited scope to offset the investments with flexibility, because the DER would have to be located in very specific locations to provide this service.125

It is therefore reasonable to assume when assessing the case for business separation that the scope for competition in most LV reinforcement projects is extremely limited. Moreover, if tenders are run for smaller HV and LV projects where competition is limited, after separation there would continue to be a need for Ofgem to regulate the conduct of the DNO in its engagements with the DSO and/or its participation in tenders that force it to compete with DERs. As of today, there is no need for these regulatory mechanisms as both the DNO’s own

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125 NERA Analysis of CV Data. See also Section 5.2.2 of this report.
costs and the costs of payments to third parties are covered by the TIM which encourages total cost reduction.

If separation is pursued, customers may ultimately face higher costs and DNOs could achieve increased returns if new regulatory mechanisms to oversee the conduct of the DNO and mitigate its local energy markets are not effective. And even if it is successful in mitigating DNOs’ market power in local energy systems, the administration and regulation of this interface between the DNO and DSO would absorb human capital and impose costs on the industry (as we discuss in Chapter 5).

4.10. Evidence on the Extent of Asset Ownership Bias

4.10.1. The CBA performed to support ESO separation assumed a 1-10 per cent overspend on capex

The problems identified above, regarding conflicts of interest potentially leading network owners to favour asset solutions, are theoretical concerns that may have real effects. However, quantifying the extent of these problems is challenging, both at the transmission and distribution level, for a number of reasons:

- In the case of distribution, flexibility is a new service and market that is still developing. Hence, its potential scale (irrespective of the existence and extent of asset ownership bias by DNOs) is unknown.
- Even in the case of transmission, the asset ownership bias is a hypothetical effect, and is not measurable. One cannot observe a counterfactual set of costs in which any alleged biases do not exist. Even a bottom-up review of TOs’ or DNOs’ investment decisions is unlikely to reveal its extent or existence, as any identifiable asset ownership bias revealed by such a review would probably have been eliminated through direct regulatory oversight of companies’ investment plans (e.g., in the cost assessment performed at price reviews) and a transition to more data transparency (e.g., via the Open Networks project).

Given the absence of direct evidence, the CBA commissioned by Ofgem from FTI to examine the effects of ESO separation quantifies the benefits of removing the conflict of interest around asset ownership bias using a switching analysis. FTI’s approach is based on two assumptions. First, expenditure (totex) levels increase steadily with a rate of change between 1 per cent and 3.5 per cent per annum over the period to 2050. Second, Ofgem instructed FTI to assume that the reduction in expenditure in the case of complete unbundling is in the range of 1 to 10 per cent.126

In the context of assessing the case for DSO separation, it is important to note that these instructions from Ofgem are not supported by any published evidence or justification, beyond an assumption that ESO separation would reduce costs. It may be that Ofgem’s experience of regulating the National Grid TO and SO business units over many years had led it to believe that such savings were possible, and we cannot comment on Ofgem’s experiences in this regard as they are not articulated or demonstrated publicly. However, in the case of DSO separation, there cannot be any similar basis for asserting that such savings are possible.

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The DSO function is only now being developed by the DNOs, the market mechanisms and platforms to support flexibility procurement are still in development, and the DNOs’ methods to assess flexibility bids against network solutions remain in development. As we note in Section 4.3 above, there is undoubtedly scope to improve the use of flexibility to reduce distribution costs, but there is no evidence as yet that any inefficiencies in the use of flexibility stem from DNOs’ asset ownership biases. There has not been enough time for this evidence to emerge.

Also, as we explain in Section 4.5, unlike at the transmission level, the small scale of distribution network investments means there is much less scope for DNOs’ proposed investments to be competitively tendered through “early competition”, and there are no proven benefits from doing so. Hence, the risk of DNOs favouring their own assets over those of third parties is negligible. By contrast, this factor was considered in Ofgem’s assessment of the case for ESO separation.127

Finally, while the ESO is a monopoly with a strategic role in shaping the future energy system across the country, the DNOs (or DSOs) are not the only operators. In regulating regional gas and electricity distribution networks (similar to Ofwat’s approach for regional water and wastewater companies), Ofgem has the ability to compare operating performance and costs of the DNOs serving different parts of the country. As such, it is more likely than at the transmission level that instances of DNOs operating inefficiently, offering inadequate service quality, or making too little progress in developing flexibility markets could be identified and the problems addressed. Hence, some form of comparative regulation may also improve outcomes, without the need for business separation.

Therefore, as a starting point, it would be unreasonable to assume any more than half of the potential 1 to 10 per cent savings in expenditure that Ofgem assumed could be achieved following ESO separation could be achieved through the full DSO separation of the DSO and DNO. We therefore take a starting point for the potential savings a range between 0.5-5 per cent of DNOs’ total expenditure over the period to 2050.

4.10.2. The benefits of totex regulation suggest the costs of asset ownership bias may be substantially mitigated

In addition to the lack of evidence for any asset ownership bias in the DSO function, there are also a number of reasons to expect the degree of any such bias to be less in distribution than in transmission.

As noted in Section 4.3.3 above, the TIM for DNOs covers both the costs of asset solutions delivered by the DNO itself and any payments to third parties. By contrast, the use of the equivalent TIM for transmission was limited to the individual TOs (including National Grid’s TO), so only covered the opex and capex incurred to provide network solutions. Payments to third party flexibility providers were remunerated separately via the SO part of the price control.

Hence, at the time the potential benefits of SO separation were assessed, there was no regulatory mechanism in force to ensure an efficient cost balance between network and non-

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network solutions. We would therefore expect the benefits of avoiding asset ownership bias to be materially lower in distribution than transmission.

To consider the potential effect of totex regulation on the benefits of avoiding biases in favour of some solutions over others, we have reviewed the empirical analysis of the benefits of introducing totex regulation in the water and energy sectors, commissioned by Ofwat from KPMG. As explained in Section 4.3.6 above, KPMG identified potential expenditure reductions of 1.3 per cent due to the benefits of totex regulation, based on an assessment of cost savings from a sample of projects.

However, this estimate assumes no cost savings at all for other categories of projects, which is highly conservative; we would not expect the benefits to be so large for other categories of expenditure that KPMG did not sample. The sample was selected, specifically to highlight the benefits of totex regulation, so provides an upwardly biased estimate of the benefits of totex regulation if applied to other categories of costs outside of the sample. We therefore:

▪ Take the 1.3 per cent estimate of the benefits of totex regulation as a lower bound, assuming (very conservatively) that totex regulation had no benefits outside of the cost categories or projects sampled by KPMG.

▪ In addition to these benefits, to derive an upper bound, we assume that totex regulation also reduces costs in other categories of expenditure, but that the effects are only 10 per cent of those estimated for projects and cost categories included within KPMG’s sample. This approach suggests an upper bound estimate of the expenditure reductions due to totex regulation of around 6.5 per cent.

There is therefore a range of uncertainty around the benefits of totex regulation, but these benefits certainly appear to be in the same order of magnitude as the benefits that could plausibly be ascribed to removing asset ownership bias. In essence, it is likely that the problem of asset ownership bias that ESO separation was intended to solve may already have largely been addressed through the benefits of totex regulation at the distribution level covering both DNOs’ own costs, as well as payments to third party flexibility providers.

4.10.3. **Other, “lighter touch” regulatory interventions can reduce any remaining asset ownership without full business separation**

As noted above in Section 4.3.7, while the totex framework significantly reduces the risk of asset ownership bias and may even encourage DNOs to favour flexibility in the short run, there remains some risk that DNOs will have a long-term preference towards using asset solutions delivered themselves, over solutions provided by third parties.

Ofgem may wish to consider how to address this, and it may well be possible to do so before resorting to costly business separation. As explained in Section 4.3.8, a number of possible solutions that could improve DNOs’ use of flexibility include encouraging local providers to provide more flexibility, perhaps with Ofgem creating schemes to incentivise DNOs to educate local energy users on how to enter and participate in flexibility markets.

Hence, undertaking costly business separation that would entail significant costs would not be justified to avoid a perceived or assumed asset ownership bias without evidence or experience showing that such a bias exists, given other, much less costly regulatory interventions to alleviate it have not yet been implemented.
4.11. Conclusions on the Potential Benefits of DSO Separation

We explain in this chapter that there are a number of potential sources of benefit from the separation of the DSO from the DNO, notably the avoided potential for the DNO to exercise bias in favour of its own businesses, and against the services provided by others. These potential sources of discrimination, and our conclusions in relation to each of them are summarised in the table below, including an assessment of the impact of different forms of business separation on removing such potential sources of discrimination.
Table 4.1: Summary of Key Sources of Potential Benefit from DSO Separation

<table>
<thead>
<tr>
<th>Potential Avoided Bias from Business Separation</th>
<th>Extent of Bias and Potential for Mitigation without Business Separation</th>
<th>Overall Likely Effect of Separation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Potential discrimination in favour of asset solutions provided by the DNO above flexibility solutions provided by DERs, stemming from the incentive DNOs have to promote growth in their RAVs (see Section 4.3).</td>
<td>▪ DNOs may favour more expensive capital solutions to increase their RAVs and hence the value of their businesses. Particularly in the long term (i.e., across different price controls), DNOs may have incentives to expand their networks to influence their capitalisation rate and grow their RAVs.</td>
<td>▪ The effect of asset ownership bias is likely to be very small, e.g., no more than 1-2 per cent of total expenditure, if they exist at all. They could be weakened with ringfencing, but probably require legal separation of the DSO from DNO to eliminate them entirely.</td>
</tr>
<tr>
<td>Potential discrimination in favour of asset solutions provided by the DNO above flexibility solutions provided by DERs, stemming from established cultural or managerial practices within DNOs (see Section 4.3).</td>
<td>▪ Established management and cultural aspects of DNO businesses and embedded planning practices may push DNOs towards network investment over operational alternatives.</td>
<td>▪ This factor would not be affected materially by business separation, especially while new planning practices are new.</td>
</tr>
<tr>
<td>▪ Important mitigants are already in place. Particularly the TIM, but also other aspects of the price control and the emergence of a market for flexible solutions offered by DERs, suggest that this bias is materially less than in transmission.</td>
<td>▪ But this is unlikely to be affected by separation as the same planners would be working within (and same planning standards applied by) the integrated DNOs or separated DSOs. Any such biases are likely to be eroded anyway as new industry planning processes bed-in over the coming years.</td>
<td></td>
</tr>
<tr>
<td>Potential Avoided Bias from Business Separation</td>
<td>Extent of Bias and Potential for Mitigation without Business Separation</td>
<td>Overall Likely Effect of Separation</td>
</tr>
<tr>
<td>-------------------------------------------------</td>
<td>------------------------------------------------------------------------</td>
<td>------------------------------------</td>
</tr>
</tbody>
</table>
| Potential discrimination against larger distribution investments that could be competitively tendered, in favour of smaller distribution investments that can be delivered by the DNO (see Section 4.5). | • DNOs may act inefficiently by favouring projects below the threshold for “early competition”, instead of bigger projects that may be more efficient, such that they deliver a higher share of projects themselves.  
• But this is a theoretical concern only, as “early competition” schemes are at a very early stage of development. Even if benefits existed, they would be much lower in distribution than in transmission. DNOs have much smaller assets, with require smaller investments, unlikely to be above the threshold. | • The effect of bias in competitive procurement is zero at the distribution level. Business separation would not have any effect. |
| Potential discrimination against transmission solutions, where these are substitutable with distribution solutions (see Section 4.6). | • Limited evidence of trade-offs that DNOs can materially influence between transmission and distribution costs, as most decisions are driven by network users’ decisions or government policy. | • This problem would not be affected by separating the DSO and DNO, as they could still show preference for investments in their own areas.  
• However, the avoided asset ownership bias from ESO integration would be negligible, because there are few trade-offs between transmission and distribution that the DSO or ESO can influence through planning decisions. |
<table>
<thead>
<tr>
<th>Potential Avoided Bias from Business Separation</th>
<th>Extent of Bias and Potential for Mitigation without Business Separation</th>
<th>Overall Likely Effect of Separation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Potential discrimination in favour of DER businesses affiliated with the DNO, and against third party DER providers, stemming from the incentive DNOs have to promote growth in affiliated businesses (see Section 4.8).</td>
<td>- DNOs may exploit their position as “upstream” monopolists to favour their affiliated businesses over other downstream competitors. New local energy markets could allow DNOs to favour the provision of flexibility services by affiliated DERs. - But this is already substantially mitigated by existing legal separation within groups and enforcement of competition law.</td>
<td>- The effect of this bias is likely to be negligible and should not be given any weight in assessing the case for DNO-DSO business separation.</td>
</tr>
<tr>
<td>DNOs may also have some incentives to favour network solutions in their advice to government</td>
<td>- The extent of DNOs'/DSOs’ advice to government is likely to be much more limited than the national ESO or FSO.</td>
<td>- Business separation may bring some, extremely small, benefit from improving the independence of advice offered to government.</td>
</tr>
</tbody>
</table>

Source: NERA analysis.
5. The Potential Costs of DSO Separation

As set out in Chapter 4 above, while there may be some benefit from DSO separation that comes from the avoidance of an asset ownership bias over the long-term, these benefits are likely to be materially lower than in transmission, remain very speculative as the market for DERs is nascent, and in any event need to be offset against the costs of separation.

Therefore, this chapter reviews the costs associated with separating the DNO and DSO activities, for the range of potential governance models identified in Chapter 3. While these are characterised as costs of separation, they could also be identified as the benefits of retaining the more integrated governance models described above.

5.1. Potential Sources of Cost from Separation

Economic theory suggests that the benefits of vertical integration are more efficient coordination between different parts of the value chain, the avoidance of transaction costs, avoidance of duplicated overheads. These benefits are greater especially when the contracting involves highly complex activities, may be infrequent, involves durable and large assets or services, involves large degrees of uncertainty over the value of assets or services, and where that value is difficult to verify by the contracting party.\(^\text{128}\)

Based on the economic theory therefore separation of a vertically integrated company would therefore result in incremental costs associated with increased coordination requirement, duplication of overheads and overall losses of vertical synergies. These costs are likely to vary depending on the level of functional and business separation of the chosen DSO governance model (as described in Chapter 3), and, as we show in the remainder of this chapter, tend to increase with stronger and deeper levels of separation between the DSO and DNO functions.

In Table 5.1 we summarise the key conceptual categories of costs associated with separation, which we discuss further in the next sections, by reviewing practical examples of these conceptual cost categories that arise due to separation.

The Potential Costs of DSO Separation

Table 5.1: Summary of Potential Losses of Synergies

<table>
<thead>
<tr>
<th>Loss of Synergy</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loss of cost synergies (economies of scope)</td>
<td>• Duplication of overheads and shared costs from creating vertically separated DNO and DSO entities.</td>
</tr>
</tbody>
</table>
| Loss of operational synergies                | • Vertical integration allows operational synergies in delivering the services required by customers from the DNO and DSO functions. Separation results in increased costs of coordination and creates “transaction costs” when the DNO and DSO need to interact.  
  • Also, because the requirements the DNO and DSO may have for services from each other may be complicated to codify, there may be a problem known in the economics literature as “imperfect contracting”, resulting in DNOs and DSOs interacting less than would be economically efficient, and the services they provide to each other not always being conducive to minimising their combined costs and maximising service quality for network users. |
| Loss of informational synergies              | • Similar to the loss of operational synergies, separating the DNO and DSO functions may reduce information exchange between the two entities. This could increase costs and reduce service quality if some parts of the business face costs or delays in obtaining the information they need. For example, control room operation, market development and planning functions may need to regularly exchange information to ensure security of supply. |
| Loss of other, less tangible synergies       | • Vertical integration allows a firm to use its resources flexibly, e.g., allowing staff to move flexibly between DSO and DNO functions depending on business need. This would become more difficult / costly under the more strictly separated governance models. |
| Financial synergies                          | • An integrated entity is likely to benefit from lower financing costs, given its larger size and potential risk from having a diversified set of activities. Financing costs could increase under the more strictly separated governance models of ownership unbundling. |

Source: NERA.

5.2. The Potential Loss of Synergies from Separation

Economic literature notes that a disadvantage of vertical separation is that it involves a loss of synergies or economies of scope. Economists identify various potential sources of economies of scope from integration.

Vertical integration results in better coordination and avoidance of transaction costs and inefficiencies stemming from imperfect contracts. Economic literature suggests that these benefits are greater when the contracting involves highly complex activities, may be infrequent, involves durable and large assets or services, involves large degrees of uncertainty over the value of assets or services, and where that value is difficult to verify by the contracting party.129 Vertical integration may enhance the availability of information and

alignment of incentives and could reduce distortions associated with market power across the value chain.\textsuperscript{130}

Many of these potential sources of vertical cost efficiencies can, at least in theory, be achieved through contractual arrangements between separate firms.\textsuperscript{131} Therefore, as the OECD notes in its guidance on restructuring public utilities for competition, to understand the costs of separation a comparison is required between the cost efficiencies achievable under integration against those achievable through contractual arrangements. If the contractual arrangements achieve the same efficiency benefits as integration, then it can be assumed that the economies of scope from integration are negligible.\textsuperscript{132}

In the electricity sector, we note that Ofgem acknowledged that the existing synergies between ESO and TO could be lost or diminished as a result of legal separation.\textsuperscript{133} However, without carrying any further analysis, Ofgem’s recommendation to legally separate ESO from National Grid was based on the assumption that “the benefit from NGET SO separation greatly exceed any loss of synergy between Gas and Electricity SO functions and Electricity TO/SO interactions”.\textsuperscript{134} Hence, Ofgem’s position was based on its judgment about the likely balance between costs and benefits.

While we discuss the potential benefits of separation in Chapter 4, in the remainder of this section we identify sources of potential economies of scope from the DNO-DSO integration, which may be lost following separation.

5.2.1. **Lack of coordination and misalignment of incentives could negatively impact reliability and security of supply**

Under the current regulatory framework, DNOs have a responsibility for achieving security of supply targets through a range of different regulatory mechanisms. First, DNOs must adhere to minimum standards of performance outlined in their licences. They have to achieve the required restoration times required under Engineering Recommendation P2/7, have obligations regarding Guaranteed Standards of Performance, and commit to maintain and improve asset health as a “secondary deliverable” under the RIIO price control.

In addition to these obligations that contribute to security of supply, DNOs are also held responsible for network reliability through security of supply standards and the Interruptions Incentive Scheme (IIS) that rewards (or penalises) DNOs for not meeting target levels of performances for unplanned and planned Customer Interruptions (CIs) and Customer Minutes Lost (CMLs).

The combination of these mechanisms ensures DNOs have a balance of incentives and obligations that protect the security and reliability of supply provided to customers. Hence,

\begin{footnotesize}
\begin{enumerate}
\item \textsuperscript{130} OECD, Restructuring Public Utilities for Competition (2001), p. 24.
\item \textsuperscript{132} OECD, Restructuring Public Utilities for Competition (2001), p. 24.
\item \textsuperscript{133} Ofgem (3 August 2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, p. 26.
\item \textsuperscript{134} Ofgem (3 August 2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, p. 26.
\end{enumerate}
\end{footnotesize}
separation of the DSO under the Widest and Wider governance models described in Section 3.3 above requires that these responsibilities be assigned to:

- The DSO which would be responsible for network planning and procuring network and non-network solutions for network expansion and maintenance; and/or

- The DNO, which would still be responsible for delivering and implementing those plans, would retain operational responsibility for restoring service after faults arise, and may retain some degree of discretion an autonomy in the decision-making around specific investment decisions.

In practice, therefore, both the DNO and DSO could be responsible for ensuring reliability and security of supply, depending on the allocation of responsibilities between them. This creates a risk that responsibilities for maintaining security of supply will “fall between the gaps” of the roles defined for the separated entities. Indeed, as noted by Burger et al (2019):

“The DNO would then be responsible for implementing IDSO network expansion and maintenance plans, although the IDSO may not have the legal authority to force a legally distinct DNO to make any specified investment. The DNO will retain some autonomy in determining how to implement network plans. Neither the IDSO nor DNO would be solely responsible for ensuring reliability, which creates a “moral hazard in teams” problem; that is, both parties have an incentive to free ride off of the other party’s efforts to ensure reliability”.

To make some practical examples:

- Under a separated model in which the DSO is responsible for network planning, it is likely that the security of supply standard (P2/7) would need to become an obligation on the DSO, as the DNO would not be able to choose itself whether to comply with it because it would not take planning decisions. For instance, National Grid ESO is required by its licence, to plan, develop and operate the National Electricity Transmission System (NETS) in accordance with the Security and Quality of Supply Standard (SQSS). However, whether the system actually delivers the required levels of network capacity following the planning decisions taken by the ESO to adhere to the planning standards would be determined by the DNO’s ability to deliver investments. If the ESO’s understanding or knowledge about the time required to deliver certain upgrades to the network are wrong, or there are delays or inaccuracies in the communications between DNO and DSO, the network upgrades may not be delivered at the time or for the cost expected by the ESO when taking planning decisions.

- Under a separated model, the current IIS mechanism that rewards/penalises DNOs for changes in CIs/CMLs may need to be revised. Depending on the responsibilities allocated to the DNO and DSO businesses, DNOs would almost certainly retain responsibility for at least some activities that affect CI/CML performance, such as maintenance policies and emergency fault restoration capacity, while the DSO would also influence CIs/CMLs through longer-term planning decisions. Hence, both parties would be exposed to each other’s decisions if they are both incentivised to improve interruption performance. This risks a “moral hazard” problem that would reduce service quality for

customers, described above by Berger (2019), and potentially increases costs because each party could – depending on the redesign of the IIS – be exposed to the performance of the other.

These practical examples of “transaction costs” may cause higher costs for consumers, delays in connections and/or security of supply problems. Such higher costs may arise both in a business-as-usual operating mode, but the same costs could increase exponentially under extreme event conditions (e.g., storms) where the clear identification and attribution of responsibilities is essential to ensure reliability of the network and security of supply for customers. It follows that business separation may result in a deterioration in the level of network security and reliability because of the challenges in defining responsibilities between the DNO and DSO, the potential moral hazard problems, and the costs and delays entailed in the interactions between the separated businesses.

5.2.2. Coordination challenges may arise at the transmission level too, but would be far more significant in distribution systems

It is possible that coordination problems exist at the interface between the TO and the ESO. As Ofgem noted in the ESO legal separation impact assessment, under the joint ownership model, the SO is an integrated part of National Grid. As a result, National Grid (as a TO) has an incentive to make decisions that help reduce constraint and other operational costs incurred by the SO. However, legal separation of the ESO from the TO will impair such an incentive.\(^{136}\)

While there are challenges in the interface between TOs and the ESO, the transmission system is considerably simpler than the distribution networks:

- While transmission systems comprise a relatively small number of large assets, distribution systems are considerably more complex, as they comprise many more assets of a lower value.
- As such, information availability is likely to be lower, e.g., DNOs themselves may not have full information about the nature and performance of their assets, as they are small (e.g., LV), potentially very old and often located underground. Hence, DNOs sometimes have to make planning decisions flexibly and pragmatically, and it would be more challenging to align such decisions between separated DNO and DSO businesses.
- As a demonstration of this, the number of interventions in the network is also much larger:
  - DNOs all interact with the network much more frequently than TOs. We estimate from the 2020/21 RRP data that the 14 DNOs have added 531,067 assets per year to their networks since the start of the ED1 period.\(^ {137}\) However, the number of interactions with the network increases exponentially as the voltage level of the network reduces. At the 132kV voltage levels, the DNOs together have added 2,424 asset units per year over ED1, as compared 8,449 asset units per year in the EHV network, 55,597 asset units per year in the HV network and 464,598 asset units per

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\(^{137}\) Data source: 2020/21 DNO RRP data: V1 – Total Asset Movement sheet.
The number of asset additions for LV are orders of magnitude higher than in the EHV or 132kV networks. Taking the 132kV network as a proxy for the transmission system, this shows that the DNOs interact far more frequently with their networks than the TOs.\footnote{When calculating the total number of asset additions, we add up the number of assets of different types added by the DNOs in over the relevant period. This requires one particular approximation, that each kilometre of cable or overhead line is treated as a single asset. However, given that lines for higher voltage networks are in general longer than lines at lower voltages, we consider the bias will underestimate the asset additions for lower voltage and potentially overestimate the number of interventions in higher voltage systems, so our estimation is conservative.}

\begin{itemize}
  \item The 14 DNOs have also repaired 170,411 faults per year in total over the ED1 period to date.\footnote{Data source: 2020/21 DNO RRP data: CV26 – Fault sheet.} The ED1 RRPs also illustrate how the number of faults falls at higher voltage levels. At the 132 kV voltage levels, the DNOs have dealt with 474 faults per year over ED1, as compared to 3,106 faults per year in the EHV network, 32,583 faults per year in the HV network and 134,249 faults per year in the LV network. Each of these incidents requires DNOs to make planning decisions in operational time horizons, e.g. on choices between repairs and replacement, and it would not be practical (i.e. prohibitively costly) to consult an independent DSO on this choice. The average number of faults are orders of magnitude higher at LV and HV than at EHV and 132kV, therefore, it is reasonable to believe the DNOs need to take many more planning decisions than the TOs.

  \item Similarly, we estimate that the DNOs manage over 29 million connections and provide around 78,000 new connections each year.\footnote{As indicated by the ED1 RRP data, over the course of ED1, the total number of customers for the DNOs has increased from 29,142,564 in 2016 to 30,091,839 in 2021, which is equivalent to a 78,162 increase per year. Data source: 2020/21 DNO RRP data: M14 – Driver’s sheet.} This number of new connections is considerably higher than the number of connections to the transmission system.

  \item The complexity of – and need for flexibility in – DNOs’ planning decisions would also be significantly greater in case of unexcepted and exceptional events which require almost real-time and very fast response times by the operational DNO/DSO teams. For instance, severe winter storms require DNOs to respond quickly and pragmatically, in effect taking many planning decisions without prior notice, and all within a matter of hours.
\end{itemize}

The complexity of planning and operating distribution system, as measured by the required number and speed of planning decisions, is therefore orders of magnitude greater than at the transmission level.
### Table 5.2: Summary of Average Industry Asset Additions, Faults and Connections over ED1 to Date

<table>
<thead>
<tr>
<th>Number of units</th>
<th>Average annual asset additions</th>
<th>Average annual faults</th>
<th>Average annual new connections</th>
</tr>
</thead>
<tbody>
<tr>
<td>LV</td>
<td>464,598</td>
<td>134,249</td>
<td></td>
</tr>
<tr>
<td>HV</td>
<td>55,597</td>
<td>32,583</td>
<td></td>
</tr>
<tr>
<td>EHV</td>
<td>8,449</td>
<td>3,106</td>
<td></td>
</tr>
<tr>
<td>132kV</td>
<td>2,424</td>
<td>474</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>531,067</strong></td>
<td><strong>170,411</strong></td>
<td><strong>78,162</strong></td>
</tr>
</tbody>
</table>

*Source: NERA analysis of DNO 2020/21 RRP data.*

#### 5.2.3. In principle, new codes or contracts could address coordination challenges, but they are unlikely to be adequate in practice

Conceptually, the challenges above from separation and the coordination between DNOs and DSOs could be addressed through the development of new codes, licences or contracts. Such agreements should clearly specify the roles and responsibilities of both parties, ensuring both the DNO and DSO have aligned incentives to ensure reliability, and provide the DNO with prescriptive instructions on what investment decisions it should make when managing and operating its network.

However, such codes, licences or contracts are unlikely to cater for all eventualities. The economics literature characterises these gaps in vertically separated companies’ responsibilities as “imperfect contracts”, which can cause inefficiency. The number of assets involved and the need to negotiate maintenance, deployment as well as factoring in contingencies to limit liability for failures by the other party mean the contracts would inevitably involve significant costs in negotiating and be incomplete. The contingencies would also lead to haggling and re-negotiation after the fact. When coordination requirements are high, the costs of separation increase due to the challenges that arise with designing contracts that are complete and efficient.

Economic literature suggests that a key benefit of vertical integration is the improved coordination of investments in network infrastructure because it allows to internalise the costs of network externalities. As Meyer (2012a) notes, “[o]nly a vertically integrated company takes overall costs into account and therefore internalizes those network externalities by a joint decision-making over-all supply stages”. The physical realities of power networks means that network externalities exist, and therefore coordination is needed in

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infrastructure investments. Bauknecht and Brunekreeft (2008) and Brunekreeft and Ehlers (2006) acknowledge that that the benefits of enhanced coordination of investments in network infrastructure and distributed generation could justify vertical integration.\textsuperscript{146}

A benefit of vertical integration between DNOs and DSOs is therefore that planning and operational decisions are all internalised within a single entity, ensuring full accountability of that company for all aspects of the interface. In other words, under a more integrated model, DNOs can make operational decisions based on an assessment of how best to meet customers’ needs and deliver the requirements placed on it, considering the incentive regime created by the regulator.

This conclusion is reflected in a more recent discussion of the case for DNO-DSO separation by Burger et al. (2019) which state:

“The durable network assets involved would have high degrees of locational specificity (they must be located in the right area), capital specificity (they would have little value outside of the power system), and temporal specificity (they must be available when needed). The IDSO and DNO would negotiate these contracts in the face of significant uncertainty over load growth, DER penetration, etc. … This lends itself to a high degree of integration between the IDSO and DNO.”\textsuperscript{147}

The authors conclude that a result of the specificity and uncertainty is that such contracts would inevitably be incomplete, and the cost of negotiating would “dramatically increase transaction costs”.\textsuperscript{148}

The potential increase in transaction costs from increased coordination requirements has also been acknowledged by BEIS and Ofgem in their recent impact assessment for the creation of an independent FSO. In this context, BEIS/Ofgem cite a prior study conducted by Ofgem regarding evidence that difficulties exist currently between the National Grid ESO and both the Scottish TOs and the OFTO in coordinating and that these “may be significant”.\textsuperscript{149}

Likewise, in its 2019 response National Grid identified several barriers to the efficient operation of the ESO and TO interface, especially to make whole system decisions in the best interest of consumers, including flaws and shortcomings in the regulatory design and commercial incentives, and the high administrative burden.\textsuperscript{150}

Separation at the distribution level would be more difficult than at the transmission level, due to the greater number of assets and coordination requirements across the network. Distribution networks are significantly more complex than transmission systems, both making it harder to regulate and harder to design appropriate and complete contracts in the


\textsuperscript{149} BEIS (20 July 2021), Impact Assessment: Future of the System Operator, p. 22.

\textsuperscript{150} NGET (December 2019), Annex A7-8.03 Whole Systems, p. 24.
form of codes, licenses or agreements.\textsuperscript{151} It follows that vertical integration may the most efficient outcome in the DNO-DSO context both in terms of minimising coordination costs as well as guaranteeing network reliability for customers.

5.2.4. **Loss of informational synergies**

Between separated network and system operators, there would be a significant amount of information that would need to be exchanged to ensure the system is optimally working. Within integrated firms, this information exchange may be more efficient and enable greater coordination. Designing a system for efficient information sharing between separated firms poses a significant (and likely costly) challenge, especially given the large number of assets involved in distribution networks.

In its review of the GB energy system operation in the transmission sector, Ofgem notes the importance of what it refers to as a “feedback loop”. The concept of a feedback loop refers to the synergies between the system operators control room, market development and network planning functions.\textsuperscript{152} The feedback loop, as Ofgem notes, is particularly important in electricity, due to the “dynamic and real time nature of electricity system balancing”.\textsuperscript{153}

Industry experts have highlighted the importance for this feedback loop, with it enabling information sharing and the distribution of technical knowledge and expertise.\textsuperscript{154} Industry experts shared concerns that turning the system operator into an independent body could lead to a loss of the connection “between commercial people and engineers”, with “commercial people” then not understanding “how market development should align with system needs”\textsuperscript{155}. Similarly, separation at the distribution level could result in less efficient information sharing, and investment decision-making, due to a loss of connection between the people responsible for identifying investments driven by load growth (DSO) and those responsible for identifying investments driven by network condition (DNO).

Ofgem notes the importance of operational synergies required between system operators and transmission operators given the highly constrained nature of the electricity system and high cost of system balancing.\textsuperscript{156} System balancing is carried out by the Electricity National Control Centre (under the ESO), although can it request help from the TOs to help balance the system. Ofgem acknowledges that legal unbundling of the ESO and NGET reduced these synergies.\textsuperscript{157}

These challenges however are even greater in the distribution sector given the complexity of the networks, the millions of assets involved, and thousands of parties connected to the grid. As Burger et al. note, there is a constant need for information to flow between DNO and


\textsuperscript{152} Ofgem (25 January 2021), Review of GB energy System Operation, p. 12.

\textsuperscript{153} Ofgem (25 January 2021), Review of GB energy System Operation, p. 12.

\textsuperscript{154} Ofgem (25 January 2021), Review of GB energy System Operation, p. 41.

\textsuperscript{155} Ofgem (25 January 2021), Review of GB energy System Operation, p. 93.

\textsuperscript{156} Ofgem (25 January 2021), Review of GB energy System Operation, p. 93.

\textsuperscript{157} Ofgem (25 January 2021), Review of GB energy System Operation, p. 93.
DSOs, as shown in Figure 5.1 below.\textsuperscript{158} DNOs deploy repair crews and constantly change network topologies for maintenance purposes, and DSOs need to send real time information to the DNO to manage set points. Any communications failures would lead to significant disruption,\textsuperscript{159} and this is even more true in the context of extreme or unexpected events. This need for information flows is likely only increase as the role for DERs increases.\textsuperscript{160}

Hence, while at the transmission level ESO and TOs exchange similar levels of information, the number of assets and the more dynamic nature of distribution network management creates substantially greater challenges for DNO/DSO. While efficient information flow is possible, at least conceptually through industry codes and procedures, the DSO would almost certainly increase coordination and transaction costs relative to an integrated DNO/DSO model.

**Figure 5.1: Example of Information Flows Required between the DSO and DNO**

As well as the greater complexity of distribution systems, the challenges and costs of information exchange at the distribution level could be materially greater because of the lower level of understanding of the assets and systems themselves. The TOs and the SO have been gathering and publishing detailed information about their systems for a number of years, largely because this information is pivotal in the day-to-day operation of the wholesale market. DNOs by contrast do not have the same track record of information gathering and


publication, although improvements have been proposed in the ED2 business plans, and they also have some uncertainty about the condition and nature of their assets, as many are underground, old, have not needed to be accessed physically for many years, and have never needed to operate actively in real time.

### 5.2.5. Loss of intangible synergies and barriers to delivering of net zero

Beyond the informational and operational synergies, there are also further vertical synergies from leveraging internal capabilities and know-how, such as information sharing between staff which allows for more efficient implementation of new business processes and changes, which may be especially important for the transition to net zero.

As an example of this, in DECC’s impact assessment considering alternative separation options of the EMR function within National Grid, DECC identified intangible synergies, which would be lost under alternative EMR governance models. Beyond operational synergies, DECC identified two additional synergies, including: i) system synergies created through delivering the EMR function that would allow for better whole system planning for the SO and TO; and ii) analytical synergies that comes from leveraging expertise information from SO/TO roles to improve EMR outcomes. In appraising the case for EMR separation from National Grid, DECC discussed the potential losses of synergies under different separation options:

- For the EMR legal separation option, DECC assessed that most of the system synergies between the EMR function and the SO would be lost. Some analytical synergies would be preserved, since information could still flow from the SO to the EMR.
- For the EMR functional separation option, DECC assessed that majority of key synergies would be retained by the EMR and SO. Only some analytical synergies relating to the ‘administrative’ functions, for example, allocation of Capacity Market auctions, would be lost to some extent.
- For the SO and TO legal separation option, DECC suggested that the synergies between the EMR and SO roles would be retained under this option, however, analytical synergies that requires input from the TO would be lost, and system synergies that would allow better planning for the TO would be lost. DECC also assessed that there would be losses of synergies between the SO and TO, but considered these synergies were not within the scope of the EMR impact assessment.

BEIS/Ofgem’s impact assessment on the establishment of an independent FSO also considers the communication and learning costs of separation. DECC/Ofgem assessed that there would

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162 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 185.

163 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 112.

164 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 126.

165 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 93.
be non-quantifiable incremental costs associated with the FSO and TO communication and collaboration relative to the previously integrated gas roles. Also, BEIS and Ofgem note that the FSO, the TO, the regulator, and other relevant stakeholders would be expected to incur learning costs for familiarising with the new structure and processes.

As we further discuss in Chapter 7, the ability to leverage internal know-how and having a “whole system view” will be pivotal also in delivering Net Zero.

5.2.6. The financial costs of separation

Another cost of separation is the financial costs associated with the separated entities relative to the vertically integrated entity. Past scholarly literature suggests that an integrated firm has an advantage as it benefits from financial synergies. In the context of the DNO-DSO separation there are two potential financial costs associated with separation, that is the additional cost of borrowing of the separated entity (cost of debt) and the additional costs associated with setting up a working capital facility. We discuss each in turn below.

Economic and financial literature suggest there could be a financial cost of separation from the higher cost of capital and debt associated with smaller, separated firms compared to larger, integrated firms. The argument is that integrated firms are able to borrow and raise capital at a lower rate as larger, diversified firms face a lower risk of default compared to their smaller counterparts. The lower risk associated with larger firms creates financial economies of scale that are enjoyed by integrated firms over separated firms. The phenomenon is well known and is seen in equity markets with the return on equity for small firms generally being higher, and small company premiums also included in various pricing models.

From a welfare analysis perspective, a higher cost of equity associated with the DSO should however be treated as transfer of risk and therefore have no total welfare effects. However, this is not the case when considering the welfare impact of separation on the cost of debt. Evidence from other sectors and allowances for small company premiums on the  

cost of debt in the water industry suggests that the impact on debt should be considered as an actual cost to consumers from separation.

- Consider for example the case of the System Operator for Northern Ireland (SONI): In its latest price control the Utility Regulator (UR) established that SONI’s cost of debt was higher than the benchmark indices, which UR attributed in part to size based factors.\(^{173}\)

- A small company debt premium has also been recognised by Ofwat over successive price controls, including at PR19. Ofwat found sufficient evidence of a difference in borrowing costs for small and large companies (while controlling for other factors) and Ofwat estimated a small company debt premium of between 0.25 and 0.4 per cent.\(^{174}\)

Such additional financial cost is especially relevant in the case of ownership unbundling, and potentially under legal separation on the basis that the DSO should be regulated on a standalone basis. Under other forms of separation such as ring fencing or in a vertical integrated entity, debt can still be issued, and capital raised, at the group level. The debt issuance will therefore still benefit from the economies of scale of the larger firm. However, after undergoing ownership separation this would be no longer possible and so the new separated firm would face higher financing costs. As noted above, in utilities regulation, a small company premium has sometimes been needed to account for these higher costs.

If the DSO were to be separated from the DNO, it is reasonable to assume based on the above evidence that under a full ownership unbundling governance model the DSO would incur higher costs of debt which would translate into a higher allowance.

Ownership separation would also imply an additional loss of financial synergies associated with the working capital requirements for the separated entity. Considering the DNO-DSO context, in the case of vertical integration or ring-fencing the DSO could continue to rely on the more solid and already established financial structure of the DNO without facing the need to create its own, independent facility to be able to meet its financial obligations and cash flows.

However, in the case of ownership separation the DSO would require a working capital facility to ensure it has enough operating liquidity to manage potential cash shortfalls. This is especially relevant in the Widest DSO governance option, in which the DSO is responsible for charging DuoS and collecting revenues. If triggered, such dynamics would result in an incremental cost to consumers. The costs associated with the creation of a new working capital facility would imply higher costs for the DSO, which would ultimately be passed on to consumers.

Case studies in the energy sector in the UK provide evidence of the increased working capital costs deriving from ownership unbundling:

- Ofgem recognised that the ESO revenue collection role required compensation for risk, allowing for a return on risk capital. Specifically, Ofgem estimated a risk capital


\(^{174}\) Ofwat (January 2019), Technical appendix 4: Company-specific adjustments to the cost of capital, p.4, 22.
requirement of between £165m and £260m and an allowance of £4.1m per year, including working capital facility costs.  

- For SONI’s latest price control, UR decided for the inclusion of an allowance of £10m for a parent company guarantee to provide additional risk protection and support SONI’s Relevant System Operator (RSO) activities. Also, UR determined that SONI was allowed an additional margin of 0.5 per cent on qualifying revenues during the 2015-20 price control as a compensation for its revenue collection role.

In addition to the working capital and other costs described above, Ofgem and UR mandated further allowances for downside asymmetric risk to compensate for the perception of a higher downside risk of the ESO and SONI respectively:

- Ofgem allowed a return of £1.5m per year for asymmetric risk, particularly account for the exposure to Demonstrably Inefficient and Wasteful Expenditure (DIWE) and the nascent framework.

- UR included, to adjust for asymmetric risk, a 3 per cent margin on its forecast costs subject to a cap.

The rationale and evidence above show that the financial costs associated with separation could be substantial. Although we have not formally quantified these costs since they will depend on the exact organisational design of the industry following separation and the regulatory framework, Ofgem will have to carefully consider the impact of potential losses of financial synergies on customers from DNO-DSO separation.

5.2.7. Duplication of costs following separation

Another source of inefficiency from separation comes from the loss of economies of scope from vertical integration. Separation results inevitably in a duplication of currently shared activities and costs to enable the functioning and coordination between two new separate entities. Most obviously, this includes for instance the costs of IT, HR, finance and other business support functions. However, it may cover other indirect costs, such as asset planning activities and separate control rooms, which (depending on the allocation of responsibilities between DNO and DSO) would need to be retained by both the DNO and DSO.

To quantify the extent of possible DNO-DSO separation on the duplication of overheads, we have examined the categories of costs incurred by DNOs, to form an assessment of which categories would require duplication on separation. As Table 5.3 shows, our assessment is based on our review of the categories of costs identified by Ofgem as DSO costs and reported in the M19 Sheet of the Draft Business Plan Data Templates (BPDT) for RIIO-ED2 (column 1 of the table), and Ofgem’s DSO BPDT guidance document which allows us to map these

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175 Ofgem (2021), Decision - RIIO-2 Final Determinations – Electricity System Operator (REVISED), page 76.
cost areas onto the DSO roles defined by Ofgem (column 2 of the table) and provide a more granular breakdown and definition of costs (column 3 of the table).

Then, based on our review of the definition of DSO costs provided by Ofgem and discussion with experts from SSE, in Table 5.3 we identify two categories of costs:

- in green costs which are currently shared between the DNO and DSO, and which will require some extent of duplication if the DSO is separated; and

- in yellow costs which are considered DSO-only (e.g., flexibility payments) and therefore would not need to be duplicated and would not result in incremental costs from separation under alternative DSO governance models.

As the table shows, we assume that only a limited number of costs items are not shared with the DNO and would therefore not require any duplication, namely costs for flexibility payments and facilitation under load-related expenditure, some DSO costs associated with network operation and development and DSO labour cost (classified as non-operational capex and closely associated indirects). All other costs categories identified by Ofgem as DSO-related costs in the draft BPDT for RIIO-ED2 are instead assumed to be shared between the DNO and DSO.

To quantify the costs of possible DNO-DSO separation under the different DSO governance models identified in Chapter 3, we assume that the potential loss of economies of scope varies with the level of functional separation: the wider the scope of the separated DSO entity the larger the potential for duplication of costs. In practice, based on the definitions of functional separation provided in Chapter 3 above, and following our review of Ofgem’s ED2 BPDT and discussion with SSEN experts, we have mapped and allocated each cost item listed in Table 5.3 (see column 3) to the Narrow, Wider and Widest DSO governance options (see ticked cells under each option).

As Table shows, by construction all costs identified as DSO costs by Ofgem are allocated to the Widest option and all shared costs items (green) would need to be duplicated under the Widest option. Instead, based on our assessment we assume that 35 cost items out of a total of 44 shared cost items listed in Table 5.3 (i.e., 80 per cent) would need to be duplicated under the Wider DSO functional separation option; and only 21 cost items (i.e., 48 per cent) would need to be duplicated the Narrow DSO function separation option.

As we explain in Section 5.4 and Section 5.5 below, we rely on this categorisation of costs to estimate the potential magnitude of the loss of synergies from DNO-DSO separation under alternative DSO governance models by assuming that the ratio of the number of shared cost items under each degree of functional separation over the total number shared costs item provides a proxy for the share of costs that would require duplication.
## Table 5.3: Areas of Potential Duplication of Costs following Separation

<table>
<thead>
<tr>
<th>DSO cost category as per M19 Sheet of the BPDT</th>
<th>DSO roles based on Ofgem mapping</th>
<th>Breakdown of DSO costs defined by Ofgem</th>
<th>Part of DSO Activities?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load related</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary Reinforcement</td>
<td>Market Development</td>
<td>DSO Flexibility Service Facilitation</td>
<td>✓</td>
</tr>
<tr>
<td>Secondary Reinforcement</td>
<td>Market Development</td>
<td>DSO Flexibility Service Facilitation</td>
<td>✓</td>
</tr>
<tr>
<td>Non-load</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operational IT and telecoms</td>
<td>Network Operation</td>
<td>Network Monitoring</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Telco Networks</td>
<td>✓</td>
</tr>
<tr>
<td>Non-load</td>
<td></td>
<td>Data Storage</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Network Control</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Network Management Systems</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Operational Data &amp; Exchange</td>
<td>✓</td>
</tr>
<tr>
<td>Non-op Capex</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IT and Telecoms (Non-Op)</td>
<td>Network Operation</td>
<td>Facilitate Non-DSO Services</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Operational Data &amp; Exchange</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CIM Development</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Smart Meter Integration &amp; Other Third Party Data Integration</td>
<td>✓</td>
</tr>
<tr>
<td>Closely associated Indirects</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Engineering Management and Clerical Support</td>
<td>Network Operation</td>
<td>Facilitate Non-DSO Services</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Operational Data &amp; Exchange</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CIM Development</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Smart Meter Integration &amp; Other Third Party Data Integration</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Network Design and Engineering</td>
<td>DSO Account Management</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Network Design and Engineering</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Planning and Network Development</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Planning &amp; Data Exchange</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Planning and Network Development</td>
<td>Produce and publish DFES, network development plans and support whole system FES</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Planning and Network Development</td>
<td>Data portal</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Forecasting, Analysis &amp; Modelling</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Assessing Network Options</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Planning and Network Development</td>
<td>Flexible Connections</td>
<td>✓</td>
</tr>
<tr>
<td>Business Support Costs</td>
<td>Planning and Network Development</td>
<td>DSO Labour</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Network Policy</td>
<td>Ongoing Co-ordination activities</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Control Centre</td>
<td>Emergency Planning</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Network Operation</td>
<td>Network Control</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Network Access Planning</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Emergency Operations</td>
<td>✓</td>
</tr>
<tr>
<td>IT&amp; Telecoms (Business Support)</td>
<td>Planning and Network Development</td>
<td>Commercial &amp; Legal Management</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Stakeholder engagement in relation to the DSO</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(treatment of stakeholder related costs and activities still open)</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Network Operation</td>
<td>DSO Account Management</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td></td>
<td>IT &amp; Telecoms (Business Support)</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Planning and Network Development</td>
<td>Planning &amp; Data Exchange</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Planning and Network Development</td>
<td>Forecasting, Analysis &amp; Modelling</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Planning and Network Development</td>
<td>Assessing Network Options</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Planning and Network Development</td>
<td>Cyber security costs</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Planning and Network Development</td>
<td>DSO Flexibility Service Facilitation</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Planning and Network Development</td>
<td>Data purchasing</td>
<td>✓</td>
</tr>
</tbody>
</table>

Legend

- ✓: DSO-only
- ✓: Shared

Source: NERA analysis based on information published by Ofgem and discussions with SSE.
5.3. **Evidence on the Potential Loss of Synergies and Duplication of Costs**

There is no direct precedent from the electricity distribution sector to draw upon to estimate the on-going costs of separation associated with duplicating costs and loss of synergies under the alternative DSO governance models discussed in this report. We therefore adopt a top-down approach drawing on evidence from the economic literature, recent impact assessments published by Ofgem and BEIS for the electricity and gas transmission sector, our own econometric modelling of DNOs’ costs and evidence from other countries or sectors to appraise the potential on-going costs of separation of the DNO and DSO in Great Britain.

5.3.1. **Evidence from the literature on the economies of scope from vertical integration**

Since the 1990s, there has been extensive debate about the appropriate degree of vertical integration in the electricity and other infrastructure industries. Across all these industries, attempts to introduce competition in some parts of the value chain have led to concerns about the potential for vertical foreclosure and the advantages that vertically integrated incumbents might have over new entrants that are not involved in the natural monopoly parts of the value chain.

This policy debate has generated a vast body of economic literature that discusses the sources of economies of scope in the electricity sector and provides empirical evidence around the potential magnitude of the economies of scope from vertical integration. Very little of this literature relates directly to the decision of whether and how to unbundle DSOs from DNOs. Nonetheless, this academic and policy literature provides evidence on the costs of unbundling and provides guidance on the extent to which there are economies of scope across different elements of the value chain that may be similar to those between the DNO and DSO.

The results of our literature review show a wide range in the estimates for the degree of vertical economies in electricity, by estimating the cost savings that arise as a result of integration (and hence the corresponding increase in costs that would come from separating the businesses). Different characteristics of the companies operating in different parts of the value chain and in different geographies significantly impact the size of the vertical economies identified. For instance, empirical estimates vary depending on the size of the companies, although there lacks conclusive evidence on the direction of the relationship. Some studies have shown that economies of scope increase with firm size\(^{180}\) although others find the opposite relationship.\(^{181}\)

Also, some reviews of empirical estimates suggest that pure network separation show lower losses of vertical economies relative to wider degree of separation involving competitive supply stages (generation or retail).\(^{182}\) While not studied explicitly in much of the literature,

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it is reasonable to assume the loss of vertical economies will be higher in distribution than in transmission, due to the assets involved being both smaller and more numerous. As discussed above, a higher number of smaller assets requires greater coordination between the DNO and the DSO and also makes it harder for regulators to oversee and scrutinise particular decisions.

Overall there is clear evidence of significant vertical economies in the electricity sector reflecting the nature of the electricity sector which lends itself to vertical economies due to the need for coordination among different levels in the supply chain and need for real-time balancing.\(^{183}\)

Table 5.4 summarises the results of our literature review and provides a range of estimates of the economies of scope for utilities across different stages of the value chain and separation alternatives.\(^{184}\) The economies of scope estimate is given as a percentage of total costs, and shows by how much costs are reduced upon separation due to the presence of vertical economies. For example, a value of 10 per cent shown in a row examining “generation vs. others” would mean costs are 10 per cent higher in a firm where generation is separated from all other stages of supply than in a vertically integrated firm.

<table>
<thead>
<tr>
<th>Sector</th>
<th>Economies of Scope (% Total Cost)</th>
<th>Approach and Geography</th>
<th>Size of firms in the sample(^5)</th>
<th>Author</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation vs. others(^1)</td>
<td>4%-10%</td>
<td>Cost function approach on US 2001 data</td>
<td>Small-large</td>
<td>Arocena et al. (2009)</td>
</tr>
<tr>
<td></td>
<td>24%-29%</td>
<td>Data on US electric utilities 2001-2008 data. Cost function estimated by linear regression on a multi stage quadratic cost function</td>
<td>Small-large</td>
<td>Meyer (2012b)</td>
</tr>
<tr>
<td></td>
<td>19-54%</td>
<td>Use data from set of class A and B firms from 1981. Cost function estimated by linear regression on a multi stage quadratic cost function</td>
<td>Small-large</td>
<td>Kaserman &amp; Mayo (1991)</td>
</tr>
<tr>
<td></td>
<td>&gt;40%</td>
<td>Data on Swiss electric companies 1997-2005. Estimate a quadratic cost function using GLS.</td>
<td>Medium/ large</td>
<td>Fetz and Filippini (2010)</td>
</tr>
</tbody>
</table>

\(^{183}\) Whilst a limited number of papers have suggested the degree of vertical economies is negligible, these do not fit with the consensus in the literature that the loss of vertical economies constitute a significant cost to unbundling. See: Meyer, R. (2012a), Vertical Economies and the Costs of Separating Electricity Supply—A Review of Theoretical and Empirical Literature, *The Energy Journal*, 33(4), p. 167.

\(^{184}\) Appendix A.1 provides a full discussion of the literature.
<table>
<thead>
<tr>
<th>Sector</th>
<th>Economies of Scope (% Total Cost)</th>
<th>Approach and Geography</th>
<th>Size of firms in the sample⁶</th>
<th>Author</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>8.1%</td>
<td>Estimate using quadratic cost function on sample of US companies from 2001</td>
<td>Small-large</td>
<td>Arocena et al. (2012)</td>
</tr>
<tr>
<td></td>
<td>-8%-53%</td>
<td>Data on Norwegian electric utilities 2004-2014. Estimate using a flexible cost function</td>
<td>Small-large</td>
<td>Mydland et al. (2020)</td>
</tr>
<tr>
<td>Distribution &amp; retail vs. others²</td>
<td>10%-13%</td>
<td>Data on US electric utilities 2001-2008 data. Cost function estimated by linear regression on a multi-stage quadratic cost function</td>
<td>Medium/large</td>
<td>Meyer (2012b)</td>
</tr>
<tr>
<td>Transmission vs. others³</td>
<td>~4%</td>
<td>Data on US electric utilities 2001-2008 data. Cost function estimated by linear regression on a multi-stage quadratic cost function</td>
<td>Small-large</td>
<td>Meyer (2012b)</td>
</tr>
<tr>
<td>Transmission vs. generation⁴</td>
<td>14%</td>
<td>Estimate cost function by linear regression with interaction terms. Data on European utilities 2000-2010</td>
<td>Small-large</td>
<td>Gugler et al. (2017)</td>
</tr>
<tr>
<td></td>
<td>4.4%</td>
<td>Data from a panel of US utilities 2000-2003. Estimate using a flexible cost function</td>
<td>Medium/large</td>
<td>Triebs et al. (2016)³</td>
</tr>
</tbody>
</table>

Notes: (1) “Generation vs. others” refers to estimates for economies of scope from the separation of generation from transmission, distribution and retail; (2) “Distribution & retail vs. others” refers to estimates for economies of scope when only distribution and retail are separated from generation. (3) “Transmission vs. others” refers to estimates for economies of scope from transmission separation only; and (4) “Transmission vs. generation” refers to estimates for economies of scope from transmission separation from generation. (5) We rely on the classification used by Meyer (2012a, Table 1) and define small electricity firms as firms with an output (across all stages of the value chain) below 15 GWh, and classify all others as medium to large. Source: NERA research. See Appendix A.1 for a full discussion of the literature.

As shown in Table 5.4 above, most of the empirical evidence regarding on the degree of economies of scope in the electricity sector relies on the estimation of multi-stage cost functions to test and quantify the degree of economies of scope.¹⁸⁵ These studies therefore provide little information regarding the impact of different types of business separation (from ring-fencing to ownership unbundling) on the degree of lost economies of scope and synergies of coordination. Despite this lack of evidence, applied studies and impact

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¹⁸⁵ This involves specifying a cost function and regression techniques to estimate parameters. Using the estimated cost function, the difference in cost between producing as an integrated or separated firm can be calculated.
assessments provide insights into the potential loss of economies of scope and synergies from different degrees of business separation, as we explain in Section 5.3.2 below.

To conclude, while there is little published cost evidence on the impact of DNO-DSO separation, a range of literature shows that vertical economies are shown to be significant throughout the electricity supply chain. The literature identifies a range of uncertainty around the precise level of cost savings from vertical integration, but it shows clear evidence of substantial cost savings from vertical economies in the electricity industry that provides a benchmark for assessing the costs associated with separating DSOs and DNOs.

5.3.2. **Evidence from Ofgem and BEIS on the actual or potential costs of separating different National Grid functions and roles**

As discussed in Section 5.2 above, separation entails ongoing costs come from duplication of functions and services as well loss of operational and other synergies. There is no direct evidence of those costs from the electricity distribution sector in Great Britain, but recent studies and impact assessments by Ofgem and BEIS provide insights into the actual or potential on-going costs and potential losses of synergies from the separation of roles and functions within National Grid. We review and summarise this evidence in turn below.

- To legally separate NG ESO Ofgem allowed on-going costs of £9.1 million per year in 2016/17 prices, or £10.1 million in 2020/21 prices.\(^{186}\) These costs reflect the allowance Ofgem provided to the ESO for implementing the mandated legal separation described in more detail in Appendix A.2.1 and followed detailed scrutiny and efficiency challenge by Ofgem.\(^ {187}\) This includes mostly staff and business support costs, and includes also £1.8 million per year of ESO and gas SO (GSO) separation costs (2016/17 prices), or £2.0 million per year in 2020/21 prices. Further to identifying these actual on-going costs from legal separation, Ofgem acknowledged “that with greater separation of the ESO and TO functions, there is a risk current synergies may be lost or diminished. There is also a risk that the synergies from the gas and electricity SO working as one organisation may be lost through the separation proposed”.\(^ {188}\) However, Ofgem did not quantify these losses of synergies and simply assumed that “the benefit from NGET SO separation greatly exceed any loss of synergy between Gas and Electricity SO functions and Electricity TO/SO interactions”.\(^ {189}\)

- Prior to its legal separation, in 2013 the electricity SO within National Grid was appointed as the delivery body of the Electricity Market Reform (EMR) package.\(^ {190}\) At the time, BEIS’s predecessor (the Department of Energy and Climate Change, DECC), carried out an impact assessment of alternative separation options of the EMR and SO


\(^{190}\) DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, p. 13.
roles due to concerns around conflict of interest.\textsuperscript{191} DECC considered multiple separation options, including functional ring-fencing of the EMR and SO function and legal separation of the EMR and SO function from National Grid. DECC estimated on-going costs of SO legal separation to be between £0.50 and £1.11 per customer (2010 prices), and between £0.21 and £0.33 per customer (2010 prices) for ring-fencing the SO function.\textsuperscript{192} Hence, DECC’s analysis suggests that the one-off separation costs of ring-fencing are about 36 per cent of the costs of legal separation.\textsuperscript{193} Also, as we noted in Section 5.2.5 above, DECC suggests that legal separation may result in a loss of synergies associated with system planning and flow of expert information, but the majority of those synergies would be retained following functional separation of the EMR function.\textsuperscript{194}

- As described in detail in Appendix A.2.2, BEIS and Ofgem have been consulting on possible options for establishing an independent electricity Future System Operator (FSO) and published an Impact Assessment (IA) of the costs and benefits of alternative options. The IA finds that:
  - There are additional on-going costs for full ownership separation of the ESO based on analysis by FTI for Ofgem and those range between £2 and £4 million year.\textsuperscript{195}
  - No loss of operational synergies from ESO full ownership separation, on grounds that the “loss in operational synergies has already occurred due to the 2019 legal separation of NGESO from NGET.” However, BEIS and Ofgem note that whilst “no further losses in operational synergies are considered in modelling, there remains an uncertainty”.\textsuperscript{196}
  - Potential for loss of operational synergies from GSO separation between £70 and 410 million in NPV terms.\textsuperscript{197} These estimates reflect analysis provided by FTI for Ofgem and assume that existing synergies allow the TO to use network assets to manage constraints and balance the gas system. If access to these asset tools for balancing were lost following full separation, the GSO would need to take more commercial actions which would result in additional costs.\textsuperscript{198}

To conclude, Ofgem’s ESO legal separation impact assessment as well as BEIS’s and Ofgem’s independent FSO assessment provide a range of estimate on ongoing costs for legally separating the ESO, and additional ongoing costs to further unbundle ESO. DECC’s assessment on separating the EMR functions within National Grid also provides estimates on ongoing costs to functionally and legally separating the SO roles from TO. While none of

\textsuperscript{191} Further details are provided in Appendix A.2.3.
\textsuperscript{192} DECC’s estimates on a per customer basis use data estimated by Ofwat in its assessment of retail water separation. Source: DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, p. 55.
\textsuperscript{193} Estimated as the average of the ratio of ring-fencing costs to legal separation costs under both the lower and upper bound values reported by DECC.
\textsuperscript{194} DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, p. 35, 38.
these studies are directly related with separating DSOs in the Great Britain, they provide a good proxy for quantifying the costs associated with separating DSOs and DNOs.

5.3.3. **NERA econometric analysis finds a high share of fixed business support costs in the DNO sector**

In addition to our review of the literature, we have also carried out our own econometric analysis of DNOs’ Business Support Costs (BSC) to estimate the proportion of fixed costs within their operations, which may need to be duplicated in case a future unbundling decision requires them to be duplicated.

As a starting point for this analysis, we reviewed Ofgem’s cost benchmarking of BSCs from two recent price reviews (ED1 and T2). While we do not use these models for efficiency assessment, the statistical relationships modelled between BSC and cost drivers may be useful for identifying the degree of fixed costs within DNOs’ businesses:

- At the ED1 price control review, Ofgem applied a unit cost methodology, assuming that DNOs’ BSC were determined on a £ per unit DNOs’ Modern Equivalent Asset Value (MEAV). Ofgem’s assumed functional form for explaining BSCs is therefore both very simplistic, and assumes that costs rise proportionally to MEAV, and as such there are no economies of scale and no fixed costs.

- At RIIO-T2 Ofgem commissioned consultants ECA to perform a regression analysis of the transmission companies’ BSCs. ECA considered a number of alternative functional forms, but its recommended approach used logarithmic forms of cost and driver variables. The coefficients of this functional form provide an estimate of the elasticity of costs to the corresponding driver, i.e. the percentage increase in costs associated with 1 per cent increase in cost driver. ECA considers size drivers including revenue, total spend, employees, network length and MEAV.

To assess the degree to which DNOs’ BSCs contain fixed costs that would be duplicated, we have performed a number of Ordinary Least Squares (OLS) regressions that use a linear functional form:

- We have not used Ofgem’s ED1 approach of unit cost modelling, because this assumes (rather implausibly) that no element of DNOs’ BSCs are fixed in nature and invariant to scale or the level of workload being performed by DNOs. Hence, we cannot identify the fixed costs that would be duplicated on separation.

- Similar, we have not used a log-linear approach like ECA at T2. While the log-linear functional form is widely used in econometric cost modelling, in this case we are primarily interested in the fixed costs, identifiable by assessing what BSCs DNOs would incur if their drivers took a value of zero within a regression equation. Log-linear models

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199 MEAV is calculated by multiplying the number of assets DNOs have in each cost category (e.g., overhead pole line, and overhead tower line), multiplied by an assumed unit cost of a “modern equivalent” of these assets. In essence, it reflects the replacement cost of the network, and is designed to act within Ofgem’s benchmarking as a proxy for the scale of DNOs’ operations. Source: Ofgem (December 2014), RIIO-ED1: Final determinations for the slow-track electricity distribution companies: Business plan expenditure assessment, p. 130.

200 Ofgem (June 2019), RIIO-2 tools for cost assessment, p. 17.

201 Ofgem (June 2019), RIIO-2 tools for cost assessment, p. 49.
do not lend themselves to estimating this, because the equation cannot be evaluated at a zero value for a driver.\(^{202}\)

- Instead, our regressions use a linear functional form. Using this functional form, a statistically significant constant across our econometric models would suggest that there are fixed business support costs that do not vary with scale. Therefore, separation of DSO and DNO would lead to a duplication of the estimated fixed portion of BSCs and increase industry costs.

We have also conducted the analysis using DNO data at both the group and licensee level. At the group level, this means we sum up the data on individual licensees that belong to the same group and perform regression analysis on the sample of 6 groups over the DPCR5 and ED1 control periods, using the historical data available up to 2021, based on information in the 2020/21 RRPs. At the licensee level our regression models have more data points, as each of the 14 licensees is represented separately.

As Table 5.6 (Licensee-level data) and Table 5.7 (DNO group-level data) show, for the purpose of this analysis, we have considered a number of alternative drivers of DNOs’ BSCs. We have identified variables that we consider could be drivers of DNOs’ business support costs, including variables capturing the scale of DNOs’ network operations and investment activities.\(^{203}\)

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\(^{202}\) Logarithmic models assume a proportional relationship between costs and drivers. In the model \(\ln(\text{Cost}) = a + b \times \ln(\text{Driver})\), the coefficient \(b\) is an elasticity, characterising the percentage change in costs following a percentage change in the driver. However, the natural logarithm of a driver tends towards negative infinity as the value of the driver tends towards zero. Hence, this functional form does not provide useful information for the current purpose.

\(^{203}\) Note, unlike when performing comparative benchmarking modelling, since we are not performing efficiency assessment of DNOs’ costs, inclusion of controllable variables (e.g. load related costs) in the models would not create concerns regarding management control. Our econometric models only aim to test if the fixed component of DNOs’ BSCs is statistically significant after considering the correlation between BSCs and the size of the DNO, and estimate its size.
### Table 5.5: Candidate Drivers

<table>
<thead>
<tr>
<th>Candidate Drivers</th>
<th>Relevance as a scale variable and relevance with BSC</th>
</tr>
</thead>
</table>
| MEAV              | • It reflects the scale and the composition of the network, but differences in composition of the network (e.g., overhead v underground) not directly relevant to BSCs  
• Does not directly capture environmental factors (e.g., London or North of Scotland effects) causing differences in BSCs  
• Data revisions during ED2 suggest the asset register is not entirely accurate |
| Network Length    | • Alternative scale variables to MEAV, which may avoid some distortions associated with MEAV (e.g. OH vs UG) |
| Customer numbers  | • Fail to capture complexity of network, but this may not be as relevant for BSCs |
| Peak demand       | • Closely correlated with customer numbers. Manifest positive relationship with the size of a DNO intuitively |
| Units distributed | • Closely correlated with customer numbers, indicative of the total demand of a company, the higher the total demand a company faces, the larger it’s likely to be, and the higher BSC it may incur |
| Load related costs| • Indicative of how much a company spends on its load-related businesses, the higher the costs, the larger it’s likely to be and the higher BSC it may incur |
| Number of companies | • Applicable to group level data, may capture the extent of fixed costs at the group level, depending on the model form |

Source: NERA analysis.

All of our regressions show a statistically significant constant terms, supporting our hypothesis that there are fixed costs (either at the group or licensee level) that would need to be duplicated if the DNO and DSO were separated. Table 5.6 and Table 5.7 summarise our estimate of the degree to which total Business Support Costs are fixed, which we estimate by taking the value of constant terms in each linear regression.

- Table 5.6 shows that across a range of alternative model specifications estimated at the DNO licensee level, our estimate of the degree of fixed costs ranges per DNO licensee from £13.8 million to £21.7 million (2020/21 prices). Average annual business support costs of the 14 DNOs from 2011-21 are equal to £33.6 million (2020/21 prices), which suggests that between 41 per cent 65 per cent of the business support costs are fixed and invariant to the scale of a DNO and would therefore need to be duplicated upon separation of the DNO and DSO.

- Table 5.7 provides a similar set of results for our regressions estimated at the DNO group level, and suggests fixed costs between £13.2 million and £21.0 million per DNO group (in 2021 prices). Average annual business support costs of the 6 DNO groups from 2011-2021 are equal to £78.3 million (in 2021 prices), which means that between 19 per cent and 27 per cent of the average DNO group’s business support costs are fixed and invariant to the scale of a DNO, and would therefore need to be duplicated upon separation.
We have not considered closely which of these modelling approaches is likely to be more accurate, as in practice the small data sample means basing our analysis on a single cost function across the DNOs would imply a spurious level of accuracy.

Instead, this analysis shows that a substantial portion of DNOs’ BSCs would need to be duplicated upon separation. We also acknowledge that these estimates are high when compared to other estimates made in the ESO of FSO impact assessments reported in Section 5.3.2 above. Hence, we do not rely directly on the results of our analysis to estimate the on-going costs of alternative DSO governance models, but use them in Section 5.4.3 below as a cross check to show that costs of separation may be substantial.

Table 5.6: Summary of Regression Results on Licensee Level Data

<table>
<thead>
<tr>
<th>Drivers</th>
<th>Estimation of annual fixed BSC per Licensee (2020/21 £m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MEAV</td>
<td>13.8</td>
</tr>
<tr>
<td>Load related cost + load related cost^2 + ED1</td>
<td>21.7</td>
</tr>
<tr>
<td>Peak demand</td>
<td>17.5</td>
</tr>
<tr>
<td>Customers number</td>
<td>16.9</td>
</tr>
<tr>
<td>Units distributed</td>
<td>18.2</td>
</tr>
<tr>
<td>Network length</td>
<td>14.5</td>
</tr>
<tr>
<td>Network length + Peak demand</td>
<td>13.9</td>
</tr>
<tr>
<td>Network length + customers number</td>
<td>14.2</td>
</tr>
<tr>
<td>Customers number + load related costs</td>
<td>16.7</td>
</tr>
</tbody>
</table>

Source: NERA analysis on DNO data

Table 5.7: Summary of Regression Results on DNO Group data

<table>
<thead>
<tr>
<th>Model specification</th>
<th>Estimation of fixed costs per DNO group (2020/21 £m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BSC – load related costs + load related costs^2 + ED1</td>
<td>16.0</td>
</tr>
<tr>
<td>BSC – peak demand</td>
<td>18.4</td>
</tr>
<tr>
<td>BSC – peak demand + network length</td>
<td>15.0</td>
</tr>
<tr>
<td>BSC – network length + units distributed</td>
<td>13.2</td>
</tr>
<tr>
<td>BSC – load related costs + customer numbers</td>
<td>21.0</td>
</tr>
<tr>
<td>BSC – network length + load related costs</td>
<td>17.3</td>
</tr>
<tr>
<td>BSC – peak demand + load related costs + number of companies + ED1</td>
<td>18.9</td>
</tr>
</tbody>
</table>

Source: NERA analysis on DNO data

Appendix B provides more details on our regression modelling, including regression outputs and diagnostic tests.

5.4. Assumed On-going Costs of Separation

A comprehensive study to identify the on-going costs of DSO separation would require a data gathering process by DNOs followed by an assessment of submitted costs by Ofgem, in line
with the process followed by Ofgem for the legal separation of the ESO. These costs may vary across the DNOs, as they have different existing operating models. For instance, SPEN and SSE are part of vertically integrated groups so may draw on corporate services, and the DNOs also own different number of licensees, ranging from WPD owning four networks to ENWL owning only one.

Also, as noted by the OECD and DECC, whilst it is possible to identify the possibility of vertical economies of scope and existence of wider benefits of coordination from DSO-DNO integration (as we describe in Section 5.2 above), assessing their magnitude in practice is challenging and necessarily assumption driven.204

Hence, in the absence of actual data we adopt a top-down approach and rely on the empirical evidence from the literature on the economies of scope in the electricity sector (in Section 5.3.1 above), the costs incurred by National Grid for the ESO legal separation (in Section 5.3.2 above) and our own assessment of the areas costs shared between the DNO-DSO (in Section 5.2.7 above) to estimate the ongoing costs of separation under alternative DSO governance models.

However, to reflect uncertainty around the actual costs of DSO separation and the potential loss of synergies and how they may differ from transmission or other stages of the electricity value chain, we provide a range of estimates at the sector level for each DSO governance model, as explained more in detail below.

### 5.4.1. On-going costs of legal separation and ring-fencing at the sector level

In the absence of actual data across the companies, the costs incurred by National Grid for the legal separation of the ESO provide a reasonable proxy for the costs of legal separation of the DSOs under the assumption that a similar governance model is put in place in the distribution sector. Hence, given the uncertainty around the actual costs of DSO legal separation, we draw on the following:

- Evidence from the economic literature that suggests potential economies of scope in the electricity sector are on average equal to 19 per cent. As noted in Section 5.3.1 above, the literature covers a wide range of evidence regarding the economies of scope in the electricity sector, but does not provide direct evidence of the degree of economies of scope and synergies between the DNO and DSO roles. We therefore take the mid-point of that range as a proxy of the potential loss of economies of scope from DSO-DNO separation.

- Evidence of the additional costs of designing and developing new market and industry codes that would govern the DNO-DSO relationship upon separation. These costs would not be captured by the on-going costs of the ESO legal separation since the relationship

204 For instance, the OECD notes that: “Unfortunately, recognising the theoretical possibility of vertical economies of scope and assessing their magnitude in practice are two quite different things. The regulatory authority may not have the information it needs to accurately assess the economies of scope. However, by the establishment of a burden of proof in favour of separation creates incentives for the proponents of integration to produce evidence as to the magnitude of economies of scope.” Source: OECD (2001), Restructuring Public Utilities for Competition, p. 24.

Likewise, DECC in its impact assessment of the potential separation of the EMR function from National Grid notes that: “Some of the analysis, such as stakeholder confidence and the preservation of synergies, is difficult to measure quantitatively”. Source: DECC (10 October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 15.
between the transmission system owners and the system operator had already been detailed in 2004 through the System Operator Transmission Owner Code (STC), long before the separation in 2019 (as discussed in Section 4.2.2 above).

There is no direct precedent from the electricity distribution sector to draw upon to estimate these costs associated with developing and designing new market and industry codes. We therefore draw on evidence from the Cave Review which assessed the costs associated with designing market codes and developing markets following the potential legal separation of water companies retail operations in England & Wales. The Cave Review established that the costs of designing market codes and other costs of market development could be assumed to be “roughly twice as great as those in Scotland” (of around £5 million in 2007 prices) where competition had already been introduced.\(^\text{205}\) In drawing this conclusion, Cave noted that on the one hand, codes had already been drafted in Scotland, which could reduce relevant cost E&W). On the other hand, different circumstances and the larger number of companies in E&W could make the situation more complex in E&W than in Scotland.

From this evidence, we estimate the following ranges for the on-going costs of legal separation:

- An upper bound value of £93.5 million per year at the sector level (2020/21 prices) for the Widest option, assuming each of the 6 DNO groups would incur the same level of costs incurred by ESO for its legal separation (excluding ESO/GSO costs) of £8.1 million per year (2020/21 prices).\(^\text{206}\) We also assume that each DNO group would incur additional costs of £7.5 million per year (2020/21 prices) to design and develop new market and industry codes to govern the DNO-DSO relationship. The latter estimate reflects the ESO’s RIIO-2 operating costs for developing “code and charging arrangements that are fit for the future” of £3.7 million per annum (2020/21 prices), multiplied by two in line with the Cave review assumption mentioned above.\(^\text{207}\)

- A lower bound value of £72.2 million per year for the Widest option by assuming economies of scope for the distribution sector of 19 per cent of average yearly DSO costs over ED2 at the industry level (equal to £144.0 million per year, 2020/21 prices) and including on-going costs of £7.5 million per year per DNO group (2020/21 prices) for DNO-DSO market and industry codes, as described above.\(^\text{208}\)

- A lower and upper bound between £57.5 million and £74.4 million per year (2020/21 prices) for the Wider option, assuming on-going costs vary with the level of functional separation and estimated by scaling the above on-going separation costs for the Widest option by 80 per cent. As explained in Section 5.2.7, the latter is calculated as the ratio of

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\(^\text{205}\) The Cave Review and Defra do not provide details as to whether these are one-off costs and/or on-going costs. However, in the remainder in this report we assume that the design and development of market and industry codes entails both costs. Sources: (1) Defra (16 September 2009), Retail Water Competition 3: Impact Assessment of the legal separation of water companies retail operations, p. 11-12; and (2) Cave Interim Review (November 2008), Independent Review: of competition and innovation in Water Markets, para. A53.

\(^\text{206}\) Ofgem allowed £1.8 million on-going costs associated with the ESO and gas SO (GSO) separation (2016/17 prices), or £2.0 in 2020/21 prices. We assume these costs related to the on-going costs of separating the SO role between electricity and gas, which was previously run as a unique SO role by National Grid, and therefore exclude those from the on-going costs of DNO-DSO separation.

\(^\text{207}\) NGESO (2019), RIIO-2 Business Plan Annex 1 – Supporting Information, p. 27.

\(^\text{208}\) NERA analysis based on ENWL (2 July 2021), RIIO-ED2 Business Plan Data Template: Sheet M19, and data provided by SSEN.
the number of shared cost items under the Wider option over the total shared cost items, and assumes a one-to-one relation between costs and number of shared cost items under each degree of functional separation.²⁰⁹

There is limited empirical data regarding the on-going costs of ring-fencing and we therefore assume that the costs of ring-fencing the DSO under the Narrow, Wider and Widest options is a percentage of the costs of legal separation, assuming however there are no additional costs associated with setting up market and industry codes. Hence, we estimate:

- An upper bound value of £24.3 and £19.3 million per year at the sector level (2020/21 prices) for the Widest and Wider options respectively, reflecting a statement by DEFRA and Ofwat in the context of the potential separation of water retail companies that “the costs associated with functional separation are approximately 50% of the costs associated with legal separation”.²¹⁰
- A lower bound value of £9.8 and £7.8 million per year at the sector level (2020/21 prices) for the Widest and Wider options respectively based on DECC’s EMR impact assessment that suggests one-off separation costs of ESO ring-fencing are about 36 per cent of the costs of ESO legal separation.
- A lower and upper value of £4.7 and £11.6 million per year at the sector level (2020/21 prices) for the Narrow option assuming on-going costs vary with the level of functional separation and estimated by scaling the above on-going separation costs for the Widest option by 48 per cent. As explained in Section 5.2.7, the latter is calculated as the ratio of the number of shared cost items under the Narrow option over the total shared cost items, and assumes a one-to-one relation between costs and number of shared cost items under each degree of functional separation.

Table 5.6 summarises the results of our analysis.

<table>
<thead>
<tr>
<th>Option</th>
<th>Ring-fencing (Low)</th>
<th>Ring-fencing (High)</th>
<th>Legal Separation (Low)</th>
<th>Legal Separation (High)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow</td>
<td>4.7</td>
<td>11.6</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wider</td>
<td>7.8</td>
<td>19.3</td>
<td>57.5</td>
<td>74.4</td>
</tr>
<tr>
<td>Widest</td>
<td>9.8</td>
<td>24.3</td>
<td>72.2</td>
<td>93.5</td>
</tr>
</tbody>
</table>

Source: NERA analysis.

5.4.2. On-going costs of ownership separation and ESO amalgamation at the sector level

To estimate the on-going costs of ownership separation and ESO amalgamation at the sector level

²⁰⁹ Note that by construction the ratio for the Widest option is equal to 100 per cent.
²¹⁰ Defra and Ofwat (2 December 2011), Introducing Retail Competition in the Water Sector, p. 75-76.
the ESO / GSO, noting however that further investigation into the actual costs of separation should be carried out to appraise the exact extent of the costs of potential DSO ownership separation. Hence, we estimate:

- An upper bound value of £117.5 and £98.4 million per year at the sector level (2020/21 prices) for the Wider and Wider options respectively, by assuming each DNO group would incur £4 million additional ongoing costs for ownership separation relative to our upper bound estimated costs of legal separation cost estimated above and reflecting Ofgem/FTI’s assumption when appraising the costs of ESO ownership separation (see Section 5.3.2 above).²¹¹

- A lower bound value of £84.2 and £69.5 million per year at the sector level (2020/21 prices) for the Wider and Wider options respectively, by assuming each DNO group would incur £2 million additional ongoing costs for ownership separation relative to our lower bound estimated costs of legal separation, in line with the lower bound estimate of the additional on-going costs of ownership separation assumed by Ofgem/FTI (see Section 5.3.2 above).

Finally, we assume that the **ESO Amalgamation** option may result in some on-going cost efficiencies, for example in the costs associated with corporate overheads (e.g., IT, finance, HR), which may result in lower on-going costs relative to the ownership unbundling option at the sector level. To provide an indicative range, we therefore assume that costs at the sector level would range between 75 and 100 per cent of the total sector costs associated with the ownership unbundling (or between 4.5 and 6 times DNO-group level costs).

**Table 5.9: On-going Costs of Separation at the GB Sector Level, £m in 2020/21 prices**

<table>
<thead>
<tr>
<th></th>
<th>Ownership Unbundling</th>
<th>ESO Amalgamation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Narrow</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wider</td>
<td>69.5</td>
<td>98.4</td>
</tr>
<tr>
<td>Widest</td>
<td>84.2</td>
<td>117.5</td>
</tr>
</tbody>
</table>

*Source: NERA analysis.*

### 5.4.3. Our estimate of total on-going costs of separation may be conservative

Table 5.10 summarises the results of our assessment of on-going costs at the sector level, including on-going regulatory costs between £1.8 and £2.9 million per year (2020/21 prices) reflecting the assumptions in the Cave Review (2008) for the water sector that estimated regulatory costs between £1.2 and £2 million per year (2007 prices) based on information

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provided by Ofwat and stakeholders on the additional regulatory costs following separation of water retail.\(^{212}\)

As Table 5.10 below shows, the results of our analysis suggest that the ongoing costs of ring-fencing could range between £6.5 and £27.2 million per year (2020/21 prices). The ongoing costs of legal separation and ownership separation are substantially higher and could range between £59.2 and £120.4 million per year (2020/21 prices). The on-going costs of ESO Amalgamation could be lower than ownership separation, due to cost efficiencies from amalgamating the DSO at the regional level or within the DSO but the cost could also be the same as ownership separation if no cost efficiencies are assumed. Hence, we estimate the on-going costs of ESO amalgamation to range between £53.9 and £120.4 million per year.

**Table 5.10: Total On-going Costs of Separation at the GB Level, £m per year in 2020/21 prices**

<table>
<thead>
<tr>
<th></th>
<th>Ring-Fencing</th>
<th>Legal Separation</th>
<th>Ownership Separation</th>
<th>ESO Amalgamation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Regulatory Costs</td>
<td>1.8</td>
<td>2.9</td>
<td>1.8</td>
<td>2.9</td>
</tr>
<tr>
<td>Total Sector Costs:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Narrow</td>
<td>6.5</td>
<td>14.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wider</td>
<td>9.6</td>
<td>22.3</td>
<td>59.2</td>
<td>77.3</td>
</tr>
<tr>
<td>Widest</td>
<td>11.6</td>
<td>27.2</td>
<td>74.0</td>
<td>96.4</td>
</tr>
</tbody>
</table>

Source: NERA analysis.

We have cross-checked our results against other evidence from the literature regarding ongoing costs of separation and our own econometric analysis and find that:

- Using the per-customer estimates published by DECC in the context of the legal and functional separation assessment of the EMR function within National Grid using data estimated by Ofwat in its assessment of retail water separation (see Section 5.3.2 above), we find that the on-going costs of legal separation may be lower than the range shown in Table 5.10 above, ranging between £22.3 million to £48.5 million per year (2020/21 prices) assuming total customer numbers served by DNOs in GB is equal to about 30 million,\(^{213}\) and adding the regulatory costs. The same holds when using DECC’s estimates per customer for the on-going costs of ring-fencing, which suggests total industry costs of £10.4 million to £16.5 million per year (2020/21).

- Our econometric analysis of business support costs in Section 5.3.3 suggests that the on-going costs of separation could range between £81.0 million and £306.7 million per year at the sector level (2020/21 prices), substantially above most of the estimates reported in the table above.\(^{214}\)

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\(^{213}\) NERA analysis of 2020/21 RRP data.

\(^{214}\) We calculate the range of on-going costs for the sector level by taking the lowest and highest sector level estimates from licensee level and group level regressions. To obtain the sector level estimates, we multiply the regression estimate from the licensee level by number of licensees in the GB (i.e., 14) and add to the regulatory on-going costs;
In our analysis we have assumed that the potential for vertical economies (and therefore loss of economies of scope from separation) is equal to the mid-point of the empirical evidence from the literature (i.e., 19 per cent). However, the literature on the economies of scope illustrated in Section 5.3.1 suggests that the scope for vertical economies may be substantially higher.

Beyond the measurable impact on costs from separation in terms of economies scope, it is not possible to quantify the magnitude of the costs associated with the loss of information synergies or from inefficient contracting described in Section 5.2.1 and 5.2.4.

It follows that based on the above, our estimates of on-going costs of separation may be conservative.

5.5. The One-off Implementation Costs of Business Separation

Separation comes at a cost, and beyond the loss of synergies and duplication of costs discussed above, it entails one-off costs resulting directly from the break-up of an integrated company. These vary depending on the degree of business separation that is required, and broadly include legal, financial and consultancy costs to implement separation as well as costs associated with buildings and IT infrastructure, governance, staff, and business support costs.

There is no direct precedent from the electricity distribution sector to draw upon to estimate the one-off costs of separation under the alternative DSO governance models discussed in this report. We therefore rely on a top-down approach and draw on evidence of the costs incurred by National Grid for the ESO legal separation as well as recent and past evidence of the costs of separation of other roles and functions within National Grid, namely:

- To legally separate NG ESO incurred £49.3 million in 2016/17 prices, or £54.8 million in 2020/21 prices. These costs reflect the allowance Ofgem provided to the ESO for implementing the mandated legal separation described in more detail in Appendix A.2.1 and followed detailed scrutiny and efficiency challenge by Ofgem. This includes costs for setting up a separate legal entity and governance arrangements, physical separation of premises, informational ring-fencing, as well as costs associated with business changes and procedures, and setting up information systems. They also include £4.3 million of ESO and gas SO (GSO) separation costs (2016/17 prices), or £4.8 in 2020/21 prices.

- Prior to its legal separation, in 2013 the electricity SO within National Grid was appointed as the delivery body of the Electricity Market Reform (EMR) package. As noted in Section 5.4 at the time, DECC considered multiple separation options, including functional ring-fencing of the EMR function and legal separation of the EMR function from National Grid. DECC estimated one-off costs of legal separation to be between

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217 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, p. 13.
£1.21 and £2.44 per customer (2010 prices), and between £0.8 and £1.59 per customer (2010 prices) for ring fencing.\textsuperscript{218} Hence, DECC’s analysis suggests that the one-off separation costs of ring-fencing are about 66 per cent of the costs of legal separation.\textsuperscript{219}

- As described in detail in Appendix A.2.2, BEIS and Ofgem have been consulting on possible options for establishing an independent electricity Future System Operator (FSO) and published an Impact Assessment (IA) of the costs and benefits of alternative options. The IA assumes one-off costs for full ownership separation of the ESO of £22 million, and one-off separation costs of the GSO of £100 million based on analysis by FTI for Ofgem. BEIS/Ofgem also assume that the one-off GSO costs of £100 million range depending on the scope of the gas roles taken by the FSO: from 1 per cent if the FSO does not have a formal gas role (option 1), to 20 per cent if the FSO is responsible for gas network planning only (option 2), and up to 100 per cent if the FSO performs all day-to-day operations and all supporting functions (option 3).

While we mostly rely on the costs incurred by National Grid for the ESO legal separation to estimate the one-off costs of DNO-DSO separation, we also note that we need to account for the additional one-off costs of developing new market and industry codes that would govern the DNO-DSO relationship upon separation. Indeed, as noted also in Section 5.4 above, these costs would not be captured by the one-off costs of ESO legal separation since the relationship between the transmission system owners and the system operator had already been detailed in 2004 through the System Operator Transmission Owner Code (STC), long before the separation in 2019.

As explained in Section 5.4 above for the on-going costs of separation, there is no direct precedent from the electricity distribution sector to draw upon to estimate these one-off costs associated with developing and designing new market and industry codes. We therefore draw on evidence from the Cave Review which assessed the costs associated with designing market codes and developing markets following the potential legal separation of water companies retail operations in England & Wales. The Cave Review established that the costs of designing market codes and other costs of market development could be assumed to be “roughly twice as great as those in Scotland” (of around £5 million in 2007 prices) where competition had already been introduced.\textsuperscript{220}

In the remainder of this section, we present the one-off costs of separation under each alternative DSO governance model at the DNO owner group level (Section 5.2.1 and 5.2.2), and then provide estimates at the sector level (Section 5.2.3).

\textsuperscript{218} DECC’s estimates on a per customer basis use data estimated by Ofwat in its assessment of retail water separation. Source: DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, p. 55.

\textsuperscript{219} Estimated as the average of the ratio of ring-fencing costs to legal separation costs under both the lower and upper bound values reported by DECC.

\textsuperscript{220} Sources (1) Defra (16 September 2009), Retail Water Competition 3: Impact Assessment of the legal separation of water companies retail operations, p.11-12; and (2) Cave Interim Review (November 2008), Independent Review: of competition and innovation in Water Markets, para. A53.
5.5.1. One-off implementation costs of ring-fencing and legal separation at the DNO owner group level

An accurate estimate of the costs of DSO legal separation would require a data gathering process by DNOs followed by assessment of submitted costs by Ofgem, in line with the process followed by Ofgem for the legal separation of the ESO. As noted for the on-going costs of separation in Section 5.4 above, these costs may vary across the DNOs, as they have different existing operating models.

In the absence of actual data across the companies, the costs incurred by National Grid for the legal separation of the ESO provide a reasonable proxy for the costs of legal separation of the DSOs under the assumption that a similar governance model is put in place in the distribution sector. However, to reflect uncertainty around the actual costs of DSO legal separation and how they may differ from transmission, we provide a range of estimates:

- An upper bound value for the Widest option of £62.1 million (2020/21 prices) on the assumption that one-off separation costs do not vary materially with size of the business or the level of functional separation and therefore each DNO group would incur the same level of costs incurred by ESO for its legal separation, i.e., £50.1 million in 2021/21 prices (excluding ESO/GSO costs).\(^{221}\) We also assume that each DNO group would incur an additional one-off costs of £12 million to set up DNO-DSO industry codes and arrangements. We compute these costs by assuming a doubling of some of the ESO business change costs from legal separation,\(^{222}\) in line with Cave review assumption described above.

- A lower bound value for the Widest option of £27.6 million (2020/21 prices) assuming one-off separation costs would scale with size of the DNO group. Hence, we scale the ESO legal separation costs of £50.1 million by the industry average RAV per DNO group relative to National Grid’s total RAV (i.e., 31 per cent),\(^{223}\) and include the additional one-off costs of £12 million to set up DNO-DSO industry codes and arrangement. We assume the latter do not scale with size, but note that our lower bound may be a conservative estimate of the one-off costs of separation as it assumes all one-off costs scale with size.

- A lower and upper bound value for the Wider option between £22.0 million to £49.4 million (2020/21 prices) assuming one-off separation costs could vary with the level of functional separation, and estimated by scaling all the above one-off legal separation costs for the Widest option (£27.6 million and £62.1 million, respectively) by an assumed

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\(^{221}\) Ofgem allowed £4.3 million one-off costs associated with the ESO and gas SO (GSO) separation (2016/17 prices), or £4.8 in 2020/21 prices. We assume these costs related to the one-off costs of separating the SO role between electricity and gas, which was previously run as a unique SO role by National Grid, and therefore are not relevant in the DNO-DSO context. Source: Ofgem (2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, p. 22.

\(^{222}\) We assume the following “Business Change” costs allowed by Ofgem for the ESO legal separation provide a proxy for the costs of developing markets and industry codes (values in 2016/17): People and process design (£2.1m), Regulated and contractual change (£6.4m) and stakeholder and communications (£2.3m). We assume these costs will need to be incurred twice reflect the costs of setting up DNO-DSO industry codes and arrangements. Source: Ofgem (2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, p. 22.

\(^{223}\) Estimated as ratio of: (1) DNO’s RAV at the industry level (average across the six groups) as of 31 March 2021 and equal to 4,631 million (2020/21 prices) and (2) National Grid’s total RAV, including both the TO and ESO businesses, as of 31 March 2021 and equal to 14,843 (2020/21 prices). Source: NERA analysis of Ofgem’s RIIO-ED1 Price Control Financial Model for the Annual Iteration Process November 2021 and Ofgem’s RIIO-ET1 Financial Model following the Annual Iteration Process 2019.
80 per cent factor. As explained in Section 5.2.7, this scaling factor reflects the ratio of the number of shared cost items under the Wider option over the total shared costs items, and assumes a one-to-one relation between costs and number of shared cost items under each degree of functional separation.\textsuperscript{224}

To estimate the one-off costs of ring-fencing the DSO, we assume DNOs would incur a similar set of costs as those incurred for legal separation for ensuring physical, staff and informational system separation, but limited or no costs at all for implementing operational, financial and governance separation on grounds that our definition of the ring-fencing separation option does not assume any financial, accounting or governance separation, as explained in Section 3.2.2.

There is limited empirical data regarding the one-off costs of ring-fencing and we therefore assume that the costs of ring-fencing the DSO under the Narrow, Wider and Widest options is a percentage of the costs of legal separation and assuming there are no additional costs associated with setting up market and industry codes. Hence, we rely on the costs of legal separation estimated above and estimate:

- An upper bound value of £32.9 million (2020/21 prices) for the Widest option and £26.1 million (2020/21 prices) for the Wider option by scaling the corresponding upper bound costs of legal separation (excluding DNO-DSO market code costs) by a factor of 66 per cent. As explained above, the scaling factor is in line with DECC’s EMR impact assessment that suggests per customer one-off separation costs of ring-fencing are about 66 per cent of the per customer costs of legal separation.\textsuperscript{225}

- A lower bound value of £7.8 million (2020/21 prices) for the Widest option and £6.2 million (2020/21 prices) for Wider by scaling the corresponding lower bound costs of legal separation a factor of 50 per cent. The scaling factor reflects statements from Defra and Ofwat in the context of the potential separation of water retail companies that “the costs associated with functional separation are approximately 50% of the costs associated with legal separation”.\textsuperscript{226}

- An upper bound value of £15.7 million (2020/21 prices) and a lower bound value of £3.7 million (2020/21 prices) for the Narrow option. We estimate these costs by scaling the upper and lower bound costs of legal separation cost for the Widest option (excluding DNO-DSO market code costs) by an assumed 48 per cent factor. As explained in Section 5.2.7, this scaling factor reflects the ratio of the number of shared cost items under the Narrow option over the total shared costs items. We then scale the corresponding costs by the upper (66 per cent) and lower (50 per cent) bound scaling factors described above.

Table 5.11 summarises the results of our analysis.

\textsuperscript{224} Note that by construction the ratio for the Widest option is equal to 100 per cent.

\textsuperscript{225} DECC (10 October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, p. 55.

\textsuperscript{226} Defra & Ofwat (2 December 2011), Introducing Retail Competition in the Water Sector, p. 75.
Table 5.11: One-off Costs of Separation at the DNO Group Level, £m in 2020/21 prices

<table>
<thead>
<tr>
<th></th>
<th>Ring-fencing</th>
<th>Legal Separation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Narrow</td>
<td>3.7</td>
<td>15.7</td>
</tr>
<tr>
<td>Wider</td>
<td>6.2</td>
<td>26.1</td>
</tr>
<tr>
<td>Widest</td>
<td>7.8</td>
<td>32.9</td>
</tr>
</tbody>
</table>

Source: NERA analysis.

We have cross checked these cost estimates against the per-customer estimates published by DECC in the context of the legal and functional separation assessment of the EMR function within National Grid using data estimated by Ofwat in its assessment of retail water separation (see Section 5.5 above). Assuming one-off separation cost vary with the size of companies’ customer base, we find that:

- One-off costs of legal separation may be lower than the range shown in Table 5.11 above, ranging between £8.3 and £16.7 million (2020/21 prices) assuming average customer numbers served by DNO groups in GB is equal to about 5 million. Whilst this may suggest lower costs of legal separation, we note that these estimates reflect the potential separation of a more narrow and defined function within National Grid, and may therefore under-state the one-off costs of separating DSOs from DNOs; and

- One-off costs of ring-fencing may sit towards the centre of the range shown in Table 5.11 above ranging between £5.5 and £10.9 million (2020/21 prices) assuming the same average customer numbers served by DNO groups as above.

5.5.2. One-off implementation costs of ownership unbundling and ESO amalgamation at the DNO group level

There is limited empirical evidence or studies regarding the one-off costs of ownership separation in Great Britain. We therefore rely on estimates of the costs of full separation of the ESO/GSO to estimate the cost for ownership unbundling, noting however that further investigation into the actual costs of separation should be carried out to appraise the exact extent of the costs of potential DSO ownership separation.

To capture the level of uncertainty around the actual costs of **DSO ownership separation** we estimate:

- An upper bound value for the Widest option equal to £84.3 million per DNO group (2020/21 prices) assuming incremental costs of £22.3 million for achieving a full separation relative to legal separation costs of £62.1 million. This value reflects the assumption used by BEIS(Ofgem for appraising the costs of fully separating the ESO and reflects FTI estimates.227

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227 BEIS and Ofgem note: “In all options, the full costs of separating NGESO are assumed to apply, which we have estimated as a one-off cost of separation of £22 million based on FTI’s analysis, however these are expected to be
A lower bound value for the **Widest** option of £62.1 million per DNO group (2020/21 prices) assuming one-off separation cost for full ownership unbundling are equal to the costs of legal separation. This is a conservative estimate of the costs of ownership unbundling.

An upper and lower bound value for the **Wider** option ranging between £49.4 million and £67.1 million (2020/21 prices), assuming one-off costs vary with the level of functional separation and estimated by scaling the above one-off ownership separation costs by a factor of 80 per cent. In line with our assumption for legal separation and as described in Section 5.2.7, this scaling factor reflects the ratio of the number of shared cost items under the Wider option over the total shared costs item.

To estimate the one-off costs of ESO amalgamation, we assume DNOs would incur the same set of costs as those incurred for ownership unbundling on grounds that, as we described in 3.2.5 above, the ESO amalgamation option means full ownership unbundling of the DSO from the DNO and consolidation of all DSO functions into National Grid ESO. However, as we explain in Section 5.5.3 below, when computing total costs at the industry level we assume National Grid ESO will need to incur some additional costs to merge the DSO functions within its existing organisation, whilst some cost efficiencies might be possible.

Table 5.12 summarises the results of our analysis.

### Table 5.12: One-off Costs of Separation at the DNO Group Level, £m in 2020/21 prices

<table>
<thead>
<tr>
<th></th>
<th>Ownership Unbundling</th>
<th>ESO Amalgamation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td><strong>Narrow</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Wider</strong></td>
<td>49.4</td>
<td>67.1</td>
</tr>
<tr>
<td><strong>Widest</strong></td>
<td>62.1</td>
<td>84.3</td>
</tr>
</tbody>
</table>

*Source: NERA analysis.*

We cross-check the above figures against other evidence from the literature regarding ownership separation in other countries and sectors, noting however that evidence from other countries reflect potentially more complex industry restructuring processes involving networks, retail and generation activities and that the literature does not provide details regarding the exact nature of the estimated costs:

- Nillesen and Pollitt (2019) estimate the one-off costs of ownership unbundling of distribution networks from retail activities in New Zealand in 1998 based on information from the three main players (Powerco, Vector and United Networks) at €130 per customer (in 2019 prices). This equates to about £594 million (2020/21 prices) of one-off substantially lower than the cost of fully separating the GSO". Source: BEIS & Ofgem (20 July 2021), Future System Operator Impact Assessment, p. 14.

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off costs of fully separating the DSO for an average DNO group, assuming a one-to-one relationship in customer numbers and costs.\textsuperscript{229}

- Nillesen and Pollitt (2019) estimate the one-off costs of ownership unbundling of distribution networks from generation and retail activities in the Netherlands based on information from the unbundling of Alliander from Nuon at €70 per customer (in 2019 prices).\textsuperscript{230} This equates to £320 million (2020/21 prices) of one-off costs of fully separating the DSO for an average DNO group, assuming a one-to-one relationship in customer numbers and costs.\textsuperscript{231}

- Evidence reported of the 2000 British Gas de-merger suggests one-off costs were equal to 3.2 per cent of the yearly turnover.\textsuperscript{232} This is equivalent to approximately £31 million (2020/21 prices) one-off costs of fully separating the DSOs from the DNOs.\textsuperscript{233}

### 5.5.3. One-off implementation costs of separation at the GB level

Based on our analysis above, which estimates one-off implementation costs on a “per DNO group” basis, we then estimate the total, GB-wide implementation cost of alternative DSO governance models by making the following assumptions:

- We include one-off regulatory implementation costs between £1.1 million and £6.7 million (2020/21 prices) reflecting Ofgem’s own estimate of the costs of implementing the ESO legal separation (equal to about £1 million).\textsuperscript{234} The upper end of the range assumes that Ofgem’s costs increase linearly with the number of DNO groups subject to separation. This is an upper end value, and we assume that actual costs should sit within this range reflecting some potential efficiencies in the regulatory process.

- We assume that the one-off separation costs under the ring-fencing, legal and ownership will be incurred by each DNO group. Hence, we multiply the DNO-group level costs by 6 times to compute industry level one-off costs of separation.

- We assume that the ESO amalgamation option may result in some one-off cost efficiencies, for example in the costs associated with buildings or other corporate overheads, which may result in lower one-off costs at the industry level relative to ownership unbundling. To provide an indicative range, we therefore assume ESO amalgamation costs are between 75 and 100 per cent of the costs of ownership unbundling at the industry level (or between 4.5 and 6 times DNO-group level costs).

\begin{footnotes}
\item[229] Assumes the average number of customers served by a DNO group is equal to about 5 million based on 2021 data. Assumes an FX of 1.14 Euro/GBP.
\item[231] Assumes average number of customers served by a DNO group of about 5 million based on 2021 data.
\item[234] Ofgem (2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, p. 27.
\end{footnotes}
However, we also assume that under the ESO amalgamation option the ESO itself will need to incur some costs to integrate the DSO functions and activities within its organisation. We estimate these costs for the Widest option based on the costs allowed by Ofgem for the ESO legal separation for “Business Change” and “Information Systems” of £32.7 million (2020/21 prices). In line with our approach to calculating the one-off costs of separation for the Wider option under the other business separation alternatives, we assume these costs scale with the number of shared functions relative to the Widest option (i.e. 80 per cent). We therefore estimate additional ESO costs under the Wider ESO amalgamation option of £26 million (2020/21 prices).

As Table 5.13 below shows, the results of our analysis suggest that the one-off costs of ring-fencing could range between £23.5 and £203.8 million (2020/21 prices). The one-off costs of legal separation could range between £132.9 and £379.0 million, and between £297.3 million and £512.6 million (2020/21 prices) if the DSOs were to be fully separated from the DNO groups. The one-off implementation costs of ESO amalgamation could be higher than ownership separation, due to additional integration costs from amalgamating the DSO at the regional level or within the ESO, although there may by some savings in corporate overheads. Hence, we estimate the one-off costs of ESO amalgamation to range between £249.3 and £545.3 million at the sector level.

### Table 5.13: One-off Costs of Separation at the GB Sector Level, £m in 2020/21 prices

<table>
<thead>
<tr>
<th></th>
<th>Ring-Fencing</th>
<th>Legal Separation</th>
<th>Ownership Separation</th>
<th>ESO Amalgamation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td><strong>DNO Group Costs:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Narrow</td>
<td>3.7</td>
<td>15.7</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wider</td>
<td>6.2</td>
<td>26.1</td>
<td>22.0</td>
<td>49.4</td>
</tr>
<tr>
<td>Widest</td>
<td>7.8</td>
<td>32.9</td>
<td>27.6</td>
<td>62.1</td>
</tr>
<tr>
<td><strong>Regulatory costs:</strong></td>
<td>1.1</td>
<td>6.7</td>
<td>1.1</td>
<td>6.7</td>
</tr>
<tr>
<td><strong>Total Sector Costs:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Narrow</td>
<td>23.5</td>
<td>100.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wider</td>
<td>38.4</td>
<td>163.5</td>
<td>132.9</td>
<td>302.8</td>
</tr>
<tr>
<td>Widest</td>
<td>48.0</td>
<td>203.8</td>
<td>166.8</td>
<td>379.0</td>
</tr>
</tbody>
</table>

Source: NERA analysis.

### 5.6. Total Estimated Costs of Separation and Conclusions

In this chapter we have assessed the costs DNO-DSO separation, and provided estimates of the one-off and ongoing separation costs for each DSO governance model using evidence from the literature, other impact assessment and our own analysis and assumptions. We also discuss the non-quantifiable costs associated with the proposed DNO-DSO separation.

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However, comparing our analysis against other evidence, we also note that our cost estimates are, in general, conservative.

Accounting for the monetised costs only, and as we further discuss in the Chapter 6 below, we find that ring-fencing the Narrow DSO will result in the lowest separation costs, and hence impose the least impact on customer bills. We also find that the costs of separation increase with the degree of business separation and the level of functional separation. As a result, ownership separation and ESO amalgamation for the Widest DSO are the most expensive options and are expected to increase customer bills to the greatest extent (before considering the effect of any benefits of unbundling, discussed in Chapter 4).
6. Overall Welfare Impacts

As explained in Section 2.3.3, past literature has shown a limited case for further DNO/DSO separation. However, drawing on the evaluation of costs and benefits of separation discussed in Chapter 5 and Chapter 4, in this chapter we make our own top-down assessment of the case for alternative DNO/DSO governance models outlined in Chapter 3.

As we explain below, the overarching case for separation is difficult to assess because it requires a comparison of quantitatively estimable costs against qualitative benefits. Also, such benefit assumptions cannot be well-founded as they relate to assumed benefits associated with avoided asset ownership bias that may arise in the future as the market for DERs develops (see Chapter 4). Our assessment below considers these features of the choice facing Ofgem and BEIS on how to separate (if at all) the DNOs from the DSOs.

6.1. Quantifiable Costs of Separation

To quantify cost of separating the DSO, we have investigated evidence on both the upfront costs of implementing separation, as well as the increase in on-going costs caused by the separation of businesses and the resulting loss of vertical economies.

6.1.1. On-going costs of separation

As explained in detailed in Section 5.4, absent actual data from the electricity distribution companies on the costs they would incur from separation, to estimate the ongoing costs of separation we rely on the empirical evidence from the literature on the economies of scope in the electricity sector, the costs incurred by National Grid for the ESO legal separation, and our own assessment of the areas costs shared between the DNO and DSO.

Table 6.1 summarises the results of our analysis showing a range of estimates of on-going separation cost to reflect uncertainties around the actual costs of DSO separation with our high estimates relying mostly on the actual/potential costs estimates of separating the ESO from National Grid, and our low estimates relying on empirical evidence from the literature on the economies of scope in the electricity sector. All estimates reported include an estimate of on-going regulatory costs we expect Ofgem to incur upon separation.

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236 See Section 5.4 for further details.
237 See Section 5.4.3 for further details.
As the table shows, we find that the on-going costs for separation increase as the level of business separation increases, namely:

- At the sector level, we estimate that ring-fencing results in the lowest on-going costs of separation ranging between £6.5 and £27.2 million per year (2020/21 prices). As explained in Section 5.4.1, this reflects the fact previous impact assessments by DECC, DEFRA and Ofwat suggest that the one-off cost of ring-fencing are only a fraction of the costs of legal separation, as well as our assumption that DNOs would not need to incur additional costs for developing DNO-DSO industry and market codes.

- Legal separation instead results in substantially higher on-going costs of between £59.2 and £96.4 million per year (2020/21 prices). As explained in Section 5.4.1 above, these estimates reflect the costs incurred by National Grid for the ESO legal separation (high estimates) and evidence from the economic literature on the potential loss of economies of scale in electricity sector (low estimates), as well as the additional costs to develop market and industry codes to govern the DNO-DSO relationship.

- We estimate further higher on-going costs for ownership separation ranging between £71.2 million and £120.4 million per year (2020/21 prices) reflecting, as explained in Section 5.4.2 above, the additional on-going costs associated with ownership separation assumed by Ofgem/FTI in their impact assessment of the full ESO separation.

- Finally, we provide an indicative range for the on-going costs of ESO Amalgamation between £53.9 and £120.4 million per year (2020/21 prices) with the lower bound reflecting potential on-going cost savings associated with overheads from ESO amalgamation relative to ownership unbundling. As explained in Section 5.4.3 above, to provide an indicative range we have assumed these cost savings to be between 75 and 100 per cent of the total sector costs associated with the ownership unbundling.

As the table shows, we also find that on-going costs of separation increase as the scope of the DSO functions that are separated widens from Narrow to Widest, reflecting our assessment of the shared DNO-DSO costs in Section 5.2.7 and our one-to-one relation between separation costs and the number of shared cost items under each degree of functional separation (i.e., the more cost items shared under each degree of functional separation the higher the costs of separation).
6.1.2. One-off costs of separation

As explained in detail in Section 5.5, absent actual data from the electricity distribution sector, we have estimated one-off separation costs with reference to the costs incurred by National Grid for the legal separation of the ESO, and other studies on the separation of functions and roles from National Grid as well as from other sectors (e.g., water).

Table 6.2 summarises the results of our analysis showing a range of one-off separation cost estimates to reflect uncertainties around the actual costs of DSO separation with our high estimates relying mostly on the actual/potential costs estimates of separating the ESO from National Grid, and our lower estimates assuming those same costs scale with size and therefore are lower reflecting the smaller average RAV at the DNO group level relative to National Grid.\(^\text{238}\) All estimates reported include also an estimate of the one-off regulatory costs we expect Ofgem to incur to implement separation.\(^\text{239}\)

<table>
<thead>
<tr>
<th></th>
<th>Ring-Fencing</th>
<th>Legal Separation</th>
<th>Ownership Separation</th>
<th>ESO Amalgamation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Narrow</td>
<td>23.5</td>
<td>100.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wider</td>
<td>38.4</td>
<td>163.5</td>
<td>132.9</td>
<td>302.8</td>
</tr>
<tr>
<td>Widest</td>
<td>48.0</td>
<td>203.8</td>
<td>166.8</td>
<td>379.0</td>
</tr>
</tbody>
</table>

Note: One-off costs include both DNO one-off costs as well as one-off regulatory costs.

Source: NERA analysis.

As the table shows, we find that one-off separation costs increase as the degree of business separation increases from ring-fencing to full separation:

- At the sector level, we estimate that ring-fencing results in the lowest one-off separation cost ranging between £23.5 million and £203.8 million (2020/21 prices). As explained in Section 5.5.1, this reflects the fact previous impact assessments by DECC, DEFRA and Ofwat suggest that the one-off cost of ring-fencing are only a fraction of the costs of legal separation, as well as our assumption that DNOs would not need to incur additional costs to set up DNO-DSO industry and market codes.

- Legal separation instead results in substantially higher one-off separation costs of between £132.9 million and £379.0 million (2020/21 prices). As explained in Section 5.5.1 above, these estimates assume each DNO group would incur the same level of one-off separation costs incurred by National Grid for the ESO legal separation, as well as additional costs to set up market and industry codes to govern the DNO-DSO relationship.

- We estimate further higher one-off costs for ownership separation ranging between £297.3 million and £512.6 million (2020/21 prices) reflecting, as explained in Section

\(^{238}\) See Section 5.5.1 for further details.

\(^{239}\) See Section 5.5.3 for further details.
5.5.2 above, the additional setup costs associated with ownership separation assumed by BEIS and Ofgem in their impact assessment for the electricity role of the FSO.

- Finally, we provide an indicative range for the one-off costs of ESO Amalgamation between £249.3 million and £545.3 million reflecting, as we explain in Section 5.5.3 above, on the one hand, higher costs relative ownership unbundling to capture the additional costs ESO would need to incur to merge the regional DSOs within its organisation, and on the other hand, the potential cost savings associated with overheads from merging the DSO within the ESO organisation. As we explain in Section 5.5.3, we assume these cost savings to range between 75 and 100 per cent of one-off separation for ownership unbundling.

As the table shows, we find that one-off separation costs increase as the degree of functional separation increases from Narrow to Widest, reflecting our assessment of the shared DNO-DSO costs in Section 5.2.7 and our assumption of a one-to-one relation between one-off costs and the number of shared cost items under each degree of functional separation (i.e., the more cost items shared under each degree of functional separation the higher the one-off costs of separation).

6.1.3. Present value of quantifiable costs of business separation

To quantify the overall welfare costs of the alternative business separation options, we need to make assumptions on the timing of the potential separation measures. Based on our review of the ESO legal separation process and our current understanding of Ofgem’s plan for reviewing the DNO-DSO governance arrangements, we assume that more significant changes to the industry structure would take longer to implement, with ring-fencing measures being the sole measures that could possibly be implemented before the end of RIIO-ED2.

In summary we assume that separation could be implemented with the following timings:

- Ring-fencing as from 1 April 2025 (mid of RIIO-2); and
- Legal separation, ownership unbundling and ESO amalgamation as from RIIO-ED3.

Based on these assumptions, Figure 6.1 shows our assumptions on the timing when different categories of separation costs would need to be incurred, and therefore feed into our overall welfare analysis. As the figure shows, we assume one-off costs are incurred 2 years ahead of separation taking place (spread evenly over two years), whereas on-going costs are incurred after separation has taken place.

![Figure 6.1 Assumed Timeline for Incurring One-off and On-going Separation Costs](image-url)

Source: NERA analysis.
As explained in Section 2.1 above we expect the DSO role to expand substantially in the future as we decarbonise the UK economy and achieve net zero. Hence, we assume ongoing costs of separation grow at a constant rate of 7.2 per cent (in real terms) during ED3 and ED4 assuming estimated industry DSO totex will double by the end of ED4 relative to average DSO totex in ED2. From ED5 onwards we assume on-going costs grow at a constant rate of 0.2 per cent (in real terms) in line with long-term industry average DNO totex forecasts.\(^{240}\)

We assume the separation costs are predominantly opex or short-lived capital investments like IT, and are therefore recovered in the year they are incurred, with no depreciation over time.

We use the HM Treasury Social Time Preference Rate (STPR) of 3.5 per cent to calculate the Present Value (PV) of separation costs as of 31 March 2022. We use a modelling horizon through to 31 March 2050 and obtain a time series of separation costs with ongoing costs of separation incurred each year over the forecast horizon, and the one-off cost spread evenly in the two years ahead of separation.

Table 6.3 shows the present value of total separation costs based on our estimates of the one-off and on-going costs of separation under the alternative DSO governance models discussed in this report. In summary we find that the PV of separation cost rises with the degree of functional separation (from Narrow to Wider) as well as with the level of business separation, except for our lower bound estimates for the ESO Amalgamation (of £1.3 and £1.6 billion in PV terms for the Wider and Widest options) if we assume on-going cost efficiencies could be achieved from de-merging DSOs from the current DNO groups and merging those into National Grid ESO.

Overall, our analysis shows that – regardless of which level of separation is selected between the Narrow, Wider or Widest options – the costs of separation would be substantial, and could be up to around £2.8 billion in PV terms. This equates to around £41 (2020/21 prices) for a typical residential customer.\(^{241}\)

Table 6.3: PV of Total Costs of Separation at the GB Sector Level, £m as of 31 March 2022

<table>
<thead>
<tr>
<th></th>
<th>Ring-Fencing</th>
<th>Legal Separation</th>
<th>Ownership Separation</th>
<th>ESO Amalgamation</th>
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<tbody>
<tr>
<td></td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Narrow</td>
<td>178</td>
<td>445</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wider</td>
<td>267</td>
<td>690</td>
<td>1,303</td>
<td>1,810</td>
</tr>
<tr>
<td>Widest</td>
<td>324</td>
<td>848</td>
<td>1,629</td>
<td>2,258</td>
</tr>
</tbody>
</table>

Source: NERA analysis.

\(^{240}\) NERA analysis and modelling of GB DNO totex at the industry level until 2050.

\(^{241}\) We approximate this number by dividing £2.8 billion by the total units distributed across all DNOs in 2021 (using data from the 2020/21 RRP), from which we obtain an estimate of cost per kWh of electricity distributed by the DNOs. Then we multiply this figure by the annual electricity demand from a typical residential customer, which we assume to be 3,750 kWh per year.
6.2. **Threshold of Benefits that Would Justify Separation**

As noted above, while some of the costs of separation can be estimated quantitatively, the benefits of separation are not directly observable. For example, FTI assumed a percentage of TOs’ totex would be saved through ESO separation, though this was an assumption based on Ofgem’s judgement, without any published evidentiary basis (see Section 4.2.3).\(^\text{242}\)

However, using the results from Section 6.1, we can calculate what percentage of DNOs’ totex it would be necessary to assume is avoided for separation to be justified. As a starting point for these calculations, we have used a forecast of all DNOs’ totex out to 2050:

- We model ED2 DNO totex based on companies’ draft ED business plan forecasts. We have assumed a reduction of 11 per cent from draft business plans to actual expenditure based on the reduction Ofgem applied to GD2 plans.
- Beyond ED2, we model load related expenditure (LRE) based on forecasts for ED3 and ED4 provided by SSE, which are based on the consumer transformation pathway to achieve net zero. For other DNO expenditure categories over ED3+, we model totex as past expenditure rolled forward, escalated by cost drivers. To forecast costs, we draw on established cost drivers used in Ofgem’s cost assessment process, including modern equivalent asset value (MEAV) and household growth. We model each Price Control Financial Model (PCFM) expenditure category, i.e., LRE, non-LRE asset replacement, non-LRE other, faults, tree-cutting, 100 per cent revenue pool and controllable opex.

We then convert this future totex into a stream of customer bill impacts due to the expenditure that we assume will be incurred in the future and that could be avoided following separation. To this end, we first identify the categories of costs from the PCFM that can be considered “avoidable” expenditure and against which the costs of separation should be appraised, namely:

- All capital expenditure (LRE, non-LRE asset replacement, non-LRE other) on the assumption that capital expenditure could potentially be reduced due to the benefits of DSO separation; and
- 50 per cent of the controllable opex and 100 per cent revenue pool cost categories, on the assumption that part of these costs could be avoided or reduced if the benefits of separation materialise. The 50 per cent share is an assumption, informed by our econometric analysis of business support costs (see Section 5.4) which suggests that approximately half of the business support costs at the industry level would need to be duplicated upon separation.

We exclude therefore faults and tree-cutting costs as we consider these are non-avoidable costs for the DNO, regardless from the choice of DSO separation.

We then compute a stream of customer bill impacts associated with the above “avoidable” expenditure by:

• Depreciating capital expenditure over an average asset life of 45 years, in accordance with Ofgem’s current depreciation policy for the electricity distribution sector.

• Multiplying the undepreciated capital costs by a Vanilla WACC (post tax equity, pre-tax debt) of 3.01 per cent, in accordance with the Ofgem’s latest estimate for ED2. We use a Vanilla WACC to calculate post-tax return because any tax liabilities associated with DNOs’ future totex would constitute a transfer, that is not relevant for the purpose of performing welfare analysis.

• Assuming all operating costs and the 100 per cent revenue pool are recovered as fast money in the year when the expenditure is incurred.

Finally, we sum the above and obtain a stream of future avoidable expenditure and assume that benefits can only accrue after separation has taken place, that is after 1 April 2025 for the ring-fencing option, and as from RIIO-ED3 for legal separation, ownership unbundling and ESO amalgamation, as shown in the Figure 6.2 below.

**Figure 6.2 Assumed Timeline for the Avoidable Costs (or Benefits from Separation) to Materialise**

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<td>Ring-fencing</td>
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<tr>
<td>Legal Separation</td>
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<tr>
<td>Ownership separation</td>
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<tr>
<td>ESO Amalgamation</td>
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</tbody>
</table>

**Avoidable future expenditure**

*Source: NERA analysis.*

In line with our approach to calculating the PV of costs in Section 6.1.3 above, we use the STPR of 3.5 per cent to calculate the PV future avoidable expenditure as of 31 March 2022 and use a modelling through to 31 March 2050.

We then calculate how the PV of costs of separation shown in Table 6.3 compare to the PV of these future expenditures. The ratio of separation costs to these total future distribution costs identifies the percentage of DNOs’ avoidable expenditure through to 2050 that would need to be saved in order to cover the quantifiable separation costs under each alternative governance model. The results of our analysis are presented in Table 6.4 below.

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243 We assume that Ofgem continues to apply a common depreciation profile of 45 years to the RAV.
Table 6.4: Required Threshold of Benefits Required Under Each DSO Governance Model at the GB Sector Level, £m 2020/21 prices

<table>
<thead>
<tr>
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<th>Ring-Fencing</th>
<th>Legal Separation</th>
<th>Ownership Separation</th>
<th>ESO Amalgamation</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Narrow</td>
<td>0.5%</td>
<td>1.3%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wider</td>
<td>0.8%</td>
<td>2.0%</td>
<td>4.2%</td>
<td>5.9%</td>
</tr>
<tr>
<td>Widest</td>
<td>1.0%</td>
<td>2.5%</td>
<td>5.3%</td>
<td>7.3%</td>
</tr>
</tbody>
</table>

*Source: NERA analysis.*

While the benefits of separation are hard to be quantified, there are quantifiable costs to separation. The table above reports the required cost savings that would need to materialise for unbundling of the DSO to outweigh the quantifiable costs of each type of separation, and shows that the required cost savings are the lowest from ring-fencing ranging between 0.5 per cent to 2.5 per cent of avoidable expenditure.

The table also shows, in line with our separation cost estimates, that the required cost savings increase with the level of business separation, except under our lower bound estimate for the ESO Amalgamation option where the required cost savings could be slightly lower (albeit still very substantial) than those required under ownership unbundling. The latter however holds only if we believe that substantial cost efficiencies can be achieved at the industry level which justify our lower bound assumption that separation costs of ESO amalgamation are about 75 per cent of total ownership unbundling separation costs at the industry level under our low scenario. Such an assumption is likely unrealistic given that we understand the ESO itself has also said it does not consider it should take on the DSO role.\(^\text{244}\)

As shown in Table 6.4, the threshold benefit required also rises as the scope of the separated DSO moves from Narrow to Widest reflecting our assumption of a one-to-one relation between separation costs and number of shared cost items which suggests that the wider the scope of the DSO the greater the costs of separation and therefore the larger benefit in cost savings needed to offset these costs.

Overall, we find that if any form of DSO separation takes place, there would need to be clear evidence that the DNOs can achieve a cost saving of between 0.5 per cent (for ring-fencing) to over 9 per cent (for ownership separation and ESO amalgamation) for costs where efficiencies could be achieved, i.e. LRE, non-LRE asset replacement, non-LRE other, 50 per cent controllable opex, and 50 per cent of the 100 per cent revenue pool to be justified.

### 6.3. Assessing the Quantifiable Net Benefits of Separation

As explained above, any benefits of separation are qualitative in nature, so it is difficult to draw definitive conclusions about the quantum of benefit and whether these “threshold benefits” shown in Table 6.4 would be met. However, given the high costs involved of up to almost £2.3 billion for legal separation, ownership unbundling or ESO amalgamation (see Table 6.3 above), Ofgem and government would need to make a very clear case that such

\(^{244}\) NGESO (6 May 2021), Enabling the Distribution System Operation (DSO) transition: Webinar Q+A, p. 5.
benefits exist before deciding to incur them. These costs could not be easily avoided or recovered in the future if Ofgem’s assumed benefits do not materialise, whereas separation can always be kept on the table for the future if evidence of the benefits of separation emerge later.

As explained in Section 4.2, the Ofgem impact assessment of ESO separation considered two main sources of benefit: avoidance of distortions to competition in the competitive procurement of networks, and an avoidance of asset ownership bias. However, these benefits applied to distribution are smaller and less relevant than they would be in transmission.

- Regarding avoiding distortions to competition in competitive procurement of networks, this is not a problem yet in distribution, and will not be in the foreseeable future. Distribution network investments tend to be small and made on a continual basis, rather than the fewer, large, discrete investments required in transmission. The draft business plans for RIIO-ED2 support the lack of applicability, with no projects under the draft plans being suitable for the “early competition” and “late competition” schemes proposed by Ofgem, and only one scheme reaching above £50 million in total expenditure (see Section 4.5 above). Also, the competitive procurement of transmission has not even been implemented yet. Hence, it would be unsafe to assume any benefits from this source at all can be achieved through DSO separation.

- The avoidance of an asset ownership bias would also be materially smaller than in transmission. The assumption made by Ofgem/FTI in transmission was that this bias increased total expenditure between 1 and 10 per cent and that full separation would remove these additional costs. The assumption that asset ownership bias increases costs between 1 and 10 per cent is far too high for distribution for the following reasons:

  – First, while Ofgem may have had reason to expect these savings in transmission, there cannot be any such reason to suspect DNOs of asset ownership bias yet, as the flexibility markets they would use to procure non-asset solutions are nascent. Unlike the DSO-DNO context, the activities which are now performed by the ESO were long-established functions when the separation occurred in 2019. The flexibility market is relatively new, and as explained in Section 4.3.5, the regulatory framework and business practices of DNOs are continuing to improve to utilise it, unlike ESO functions around the time of the separation that were established. Hence, as discussed also in Section 4.10, it is reasonable to half these benefits as a starting point.

  – Even then, DNOs already have strong incentives to optimise across flexibility and asset solutions, which the SO/TO framework did not allow prior to ESO separation. As demonstrated in Section 4.3.3, the totex incentive, which was not applied to transmission prior to ESO separation, represents an important mitigant by allowing DNOs to capitalise a share of both traditional network-based solutions and flexibility. Other mechanisms and developments such as the “Flexibility First”, the BPI requirements, and the CEM Tool provide other mitigants to DNOs favouring their own solutions over DERs. Hence, to some extent at least, the problem is already addressed through the regulatory framework. Indeed, as explained in Section 4.10.2,
evidence from recent research commissioned by Ofwat suggests the benefits of totex regulation could be 1-6 per cent of totex.\textsuperscript{245}

The only asset ownership bias we have identified comes through the long-term strategic incentives that the DNO may have to increase the scale (and hence value) of the distribution business. However, even this incentive may be moderated:

- The financial incentives conveyed to DNOs in the short-term via the TIM are to maximise outperformance, and using flexibility instead of asset solutions is likely to help DNOs achieve this.

- Additionally, the DNOs’ incentives to maximise totex and RAV growth, which is where the potential for asset ownership bias stems from, may already be satiated due to the potential for a very large investment requirement to support achieving net zero. This high investment requirement means that any additional investment that DNOs might make due to an asset ownership bias would probably be relatively expensive, reducing scope for outperformance of price controls.

- Given human capital and other resource constraints facing the energy networks, non-asset solutions are likely to play a significant role in managing the delivery of capital programmes. Hence, rather than competing with DNOs, flexibility is likely to play an important role in helping DNOs to deliver their capital programmes.

- Even if DNOs favour assets over flexibility today, this would in large part be down to the established, entrenched planning practices of DNOs’ planning teams, given the reforms to planning standards to allow the use of flexibility (i.e., the introduction of P2/7) and the growth in the flexibility market are extremely recent developments. These preferences for assets over flexibility due to managerial and cultural factors within DNOs may fade away over time as DNOs adjust to new planning requirements.

- If Ofgem were concerned about inefficient choices in the use of flexibility, it could consider other regulatory interventions. For instance, Ofgem could require DNOs to present evidence of having used flexibility efficiently before releasing funding for reinforcement under the uncertainty mechanisms needed to release reinforcement allowances in ED2 and beyond. Therefore, there are other mechanisms Ofgem could use to try and mitigate the potential for bias against the use of flexibility.

The result is that, overall, the benefit of avoiding asset ownership bias is unlikely to be more than 1-2 per cent of avoidable expenditure. These benefits are likely to materialise in the years after separation has been implemented.

Assuming potential benefits in the region of 1-2 per cent of avoidable expenditure means that based on our results reported in Table 6.4 only DSO ring-fencing may result in benefits potentially outweighing the one-off and on-going costs of separation (as indicated by a cost saving ratio ranging between 0.5 and 2.5 per cent of avoidable expenditure).

All other separation options assessed in this report (legal separation, ownership unbundling and ESO amalgamation) would instead result in separation costs largely outweighing any potential benefits from separation (and ranging between 4.2 and 9.4 per cent).

\textsuperscript{245} See Section 4.10.2 for further details.
It follows that our analysis of the monetised costs and benefits may suggest a case for ring-fencing, but currently there is no economic case that any other further measures of separation are in customers’ interests.

6.4. Non-quantifiable Costs Associated with Separation

The quantifiable evidence in Section 6.1 shows a significant cost to separation, coming mainly from very large one-off costs of achieving separation and the on-going costs of separation associated with the loss of economies of scope, especially from legal separation, ownership unbundling and ESO amalgamation. It also shows that the likely benefits of DSO separation are not high enough to justify these costs. However, as discussed in detail in Section 5.2, in addition to the already-high quantifiable costs of separation, there are other less tangible costs that could result from separation.

Economic theory shows that there are costs associated with imperfect contracting and coordination that can result from vertical separation. These risks are likely to be highly material when separating the DSO from the DNO, especially when compared to transmission, given the large number of small interventions that are required in distribution systems, the complex asset base, and the lack of precedent for DNO-DSO separation.

In distribution, the number of interventions required compared to transmission mean these costs could be exponentially greater than at the transmission level. In transmission, the number of assets is significantly lower making it possible for the ESO to scrutinise planning decisions and execution of projects. However, distribution assets are much smaller and more numerous, as are the investment decisions. For an independent SO to effectively oversee such decisions would be much more costly at the distribution level than the transmission level, due to the number of assets and decisions involved.

The complexity of distribution networks and specificity of assets also means the bilateral contracts negotiated between DNOs and DSOs will involve significant transaction costs and be necessarily incomplete. High levels of coordination between the two parties would be necessary for the network to function effectively, with the need to coordinate real time information to manage the network in real time, as well as coordinate on maintenance and repair over operational time horizons.

Coordination and management of these arrangements would involve contracts capable of establishing operational and planning rules governing millions of assets with both sides seeking to limit liabilities from poor performance of the other party. The negotiation of these contracts would create transaction costs that are not incurred under the integrated model, and the contracts would inevitably be imperfect relative to the integrated model which would generate inefficiency.

A separate problem from the issues of coordination and the complexity of distribution networks is that when separated DNOs and DSOs may face incentives to “free ride”; with neither the DSO nor DNO being solely responsible for reliability, both may have an incentive to free ride of the work done by the other party. There is therefore a risk that responsibilities for delivering security and reliability outputs, as well as meeting net zero, will “fall between the gaps”, causing problems for customers. Such problems could be mitigated by new regulatory mechanisms, although this entails significant costs and may not be successful in encouraging efficient behaviours in all circumstances.
To some extent these costs of separation may be included within our quantified estimates of the costs of separation, because they are based on empirical evidence regarding the loss of vertical economies from unbundling in the power sector. However, these empirical estimates do not consider DNO-DSO separation specifically, which is likely to create a much more complicated interface than between generation and transmission, or between distribution and retail. Hence, our quantifiable estimates of separation costs tend to understate the full costs of separation. As such, these non-quantifiable factors described above mean the case for separation, which as shown in Section 6.3 is already very marginal, could be eroded further.

These costs are likely to be particularly acute under the ESO amalgamation option or the ownership unbundling option, which is the level of separation at which there is no longer a single company responsible for all aspects of operating and planning the distribution system. However, they may emerge to some extent under the legal unbundling option, as the DSO and DNO would be under more severe restrictions on how they interact. These costs are also likely to be most severe in relation to day-to-day operational activities, where fast and frequent interactions between DNO and DSO are required to ensure efficient decisions. Hence, the impact will be most acute for the wider and widest DSO definitions.

Table 6.5 summarises our qualitative assessment of how each level of business separation may result in additional non-monetised costs, noting that we assume the level of functional separation has only a limited impact on these additional costs given the close definition of the Wider and Widest DSO governance models, and the Narrow definition being envisaged only under ring-fencing.

As the table show, our qualitative assessment suggests that whilst coordination, regulatory and imperfect contracting costs may be substantial following asset ownership unbundling or ESO amalgamation given that the DSO is no longer part of the same group, those non-monetised costs could potentially be more limited for legal separation on grounds that the DSO operates under the same organisation and there would be stringent company rules on coordination. We assume instead that ring-fencing may result in minimal losses of synergies and additional coordination costs as explained in Section 5.4.1, reflecting also the assumptions made by DECC in 2013 regarding the potential separation of the EMR function from National Grid.\footnote{DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 126.}
### Table 6.5: Qualitative Costs for Different Levels of Separation

<table>
<thead>
<tr>
<th>Separation Type</th>
<th>Cost of imperfect contracting</th>
<th>Cost of regulatory oversight</th>
<th>Cost of developing new regulatory instruments</th>
<th>Costs of potential free riding</th>
<th>Coordination risks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ring fencing</td>
<td>Minimal</td>
<td>Minimal</td>
<td>Minimal</td>
<td>Minimal</td>
<td>Minimal</td>
</tr>
<tr>
<td>Legal separation</td>
<td>Medium</td>
<td>Medium</td>
<td>Medium</td>
<td>Medium</td>
<td>Medium</td>
</tr>
<tr>
<td>Ownership separation</td>
<td>High</td>
<td>High</td>
<td>Medium/High</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>ESO Amalgamation</td>
<td>High</td>
<td>High</td>
<td>Medium/High</td>
<td>High</td>
<td>High</td>
</tr>
</tbody>
</table>

*Source: NERA analysis.*

### 6.5. Overall Assessment of Welfare Effects of Separation

Overall, the benefits case for separation cannot yet be made:

- The benefits of separation are intangible, and no evidence yet exists regarding their magnitude as the DSO function is only recently emerging within the DNO businesses (see Section 6.2). While the benefits of DSO separation are uncertain, the benefits of separation will likely be lower in distribution than in transmission. The greater number of smaller assets operated by DNO-DSOs compared to those operated by the ESO and TOs mean the potential inefficiency associated with DSO-DNO interactions could be exponentially greater than between the ESO and TOs. While the information exchange and need for coordination is similar at the transmission level, the more complex network and more dynamic nature of network operation and maintenance mean the challenge of effective coordination is much greater (and so the cost, both regulatory and otherwise will be much higher).

- By contrast to the intangible and unknown benefits, there exist tangible, substantial, ongoing and upfront costs to separation. The benefits remain highly uncertain, and could even be negative, whereas some of the costs associated with separation can be quantified (see Section 6.1). These costs can be avoided by retaining the current, vertically integrated model (or minimised by applying more limited ring-fencing).

- In addition to these quantifiable costs, we have also identified a number of unquantifiable costs described in Section 6.4. These include the costs of developing and maintaining new regulatory arrangements to govern the DSO-DNO interface which would also be significant, and there would be a risk of “imperfect contracting”, in which these new arrangements do not prescribe efficient behaviours. There would also be a risk of some activities or requirements “falling between the gaps”, such that service quality for customers falls.

**Hence, given the large costs and limited evidence for benefits, there is no evidence to support the more significant separation options at this stage (legal or ownership unbundling).**
There is also no evidence to support the case for the ESO amalgamation option. As explained in Section 4.6, the trade-offs between transmission and distribution costs can be made by network users within the segments of the market that are already separated and competitive, in response to regulated network charges and market conditions. ESO integration would also create the risk of diseconomies of scale since, unlike distribution systems, it was not planned in a way that is focused on meeting local stakeholders’ requirements. We understand the ESO itself has also said it does not consider it should take on this role.\textsuperscript{247}

While the cost/benefit assessment above suggests ring-fencing is not clearly cost-beneficial unless it is assumed the potential benefits of separation are below 2 per cent of avoidable expenditure, the ring-fencing option is relatively low cost to implement and would come with minimal downside risks. The implementation and ongoing operating cost impacts are lower in ring-fencing than other, more extensive forms of separation. The lower degree of separation means the costs associated are comparatively less both in terms of regulatory costs and any loss of vertical economies.

Ring fencing also achieves the benefit of creating a degree of separation between businesses and regulatory obligations. The separation could reduce market participants’ perception of any asset ownership bias. As Ofgem notes, even though there is no evidence of system operators having an asset ownership bias, the perception of a conflict of interest for the system operator can still make it difficult for system operators to effectively fulfil their roles.\textsuperscript{248} Therefore, some degree of separation through ring-fencing may go some way to removing any such perception.

Additionally, ring-fencing allows the DNOs to build up separate DSO capabilities. These capabilities do not yet exist, and Ofgem may wish to pursue separation later if evidence does emerge that there are problems with asset ownership bias in DNOs’ decision making. However, other regulatory interventions may be able to address this problem, and further separation should be pursued only if other interventions have not worked.

Hence, while our analysis suggests that the most cost-beneficial governance models is maintaining the current integrated DNO-DSO governance model (i.e., vertical integration), we recommend pursuing ring-fencing over the coming ED2 control period. This will allow time for DNOs to develop their DSO capabilities, without the loss of management time that would be caused by more severe business separation options. It also leaves open the option for Ofgem and government to pursue other separation options in the future, if evidence emerges that an asset ownership bias exists, or Ofgem develops new mechanisms for allowing competition in the delivery of distribution infrastructure that currently do not exist.

6.6. Identifying the Appropriate Degree of Functional Separation

6.6.1. The case for including long-term planning in the DSO function

As discussed in Section 4.1, the main theoretical benefit of separation (albeit there is little evidence to demonstrate it exists) is the avoidance of asset ownership bias. This potential

\textsuperscript{247} NGESO (6 May 2021), Enabling the Distribution System Operation (DSO) transition: Webinar Q+A, p. 5.
bias comes from the DSO favouring its own asset-based solution over flexibility solutions provided by DERs. Hence, to mitigate this bias it would be logical for any DSO (whatever the degree of business separation) to include the role of procuring flexibility services and contracting with third party DERs to provide flexibility services with the DNO.

As explained in Section 4.3.3, we also show that the TIM means there is little or no reason to expect a bias against flexibility in favour of asset-based solutions over the short-term, as DNOs have, if anything, financial incentives to favour flexibility over asset solutions within the control period. However, an asset ownership bias may exist in the longer-term. Hence, allocating the long-term planning responsibilities to the DSO function would be logical, as well as responsibilities for long-term development of the flexibility market.

6.6.2. Narrower DSO definitions entail lower separation costs

As shown in Table 6.3 above, the “narrower” definitions of DSOs tend to require less duplication of overheads and one-off costs of separation reflecting the fact that more limited number of functions and activities require duplication and a less complex and wide business unit needs to be separated from the existing DNO business.

Indeed, our assessment of the DNO and DSO costs in Chapter 5 above, shows that the costs of separating a Narrow DSO and Wider DSO would be around 50 per cent and 20 per cent cheaper respectively relative to separating the Widest definition of DSO. This reflects the fact that the number of shared cost items over the total number of cost items we assume require duplication following separation (which we assume provides a proxy for the share of costs that would need duplication) increase from 21 under the Narrow option, to 35 under the Wider option and up to 44 (out of 44) under the Widest option.

6.6.3. The costs and risks of misalignment in the DNO-DSO interface

Aside from separation costs, the main downside associated with separation is the risk of inefficiency on the interface between the DNO and DSO. This risk of inefficiency is discussed in detail in Section 5.2.1 and relates to the risk of inefficiency in the planning and operational decisions due to delays or costs in interacting between the two businesses, as well as the risk that responsibilities for maintaining security of supply will “fall between the gaps”. These downsides suggest that shorter-term operational and planning decisions (including despatch of flexibility resources) should remain within the scope of the DNO, so there is no need for continuous interface between the DNO and DSO over operational time horizons.

Keeping the DNO responsible for planning decisions over operational time horizons, does not address the risk of discrimination in favour of affiliated companies in despatch and curtailment. However, unbundling rules already ensure DNOs are legally separated from their affiliates in competitive segments of the market, so this should not constitute a problem that Ofgem and BEIS policy regarding DSO-DNO separation needs to address.

6.6.4. We recommend the “Wider” DSO definition

We therefore conclude that ring-fencing with a Wider definition of the DSO would be appropriate. A narrow definition would be too limited because it does not include evaluation of alternative system solutions, a key area where there is a perceived bias (albeit currently there is no evidence of an actual bias).
Conversely, the widest definition of a DSO would be too extensive because incorporating any real time operational responsibilities into the DSO creates serious risks of operational difficulties in the DNO-DSO interface harming service to customers and creating unnecessary and additional costs. A Wider definition within the two extremes would help balance these two factors.

Our quantitative cost and benefit analysis shown in Table 6.4 above also supports the implementation of a Wider definition of the DSO under a ring-fencing option of business separation, assuming that potential benefits of separation are not lower than the required cost savings of 0.8 per cent and 2.0 per cent of avoidable expenditure.
7. Effects on Delivery of Net Zero

7.1. Achieving Net Zero Requires Effort from the Power Sector

The stated aim of the government is for a complete decarbonisation of the electricity grid by 2035. The steps needed to achieve net zero by the legally binding dates of 2045 in Scotland and 2050 in England and Wales, require both significant investment and coordination among all different levels in the supply chain for electricity. Distribution and transmission operators will have to accommodate new sources of generation, and the increased role of renewables and flexible energy sources. As noted by the government, the model used for operating distribution networks “need to be updated” which will require coordination across “the regulator, networks, industry and government”. Therefore, undertaking the significant tasks and challenges associated with separating DNOs and DSOs at the same time as pursuing net zero would exacerbate both challenges.

The exact requirements that will be faced by network operators to reach net zero are uncertain. Whilst the pathway to net zero has been outlined by the government, the in-depth detail is still to be determined. However, what is clear is that there will be significant network investment needs to accommodate the shift in electricity generation, and the roles of network operators is expected to shift accordingly.

According to the government, to fully decarbonise the power sector and keep pace with increasing demand, a total of public and private investment of between £280 billion and £400 billion is needed. Specifically reinforcing and maintaining electricity transmission and distribution networks will cost between £20 billion and £30 billion by 2037. These costs will be passed on to consumers through the allowed revenues by Ofgem. More broad estimates on the investment needed in the power grid to reach net zero by PWC point to an annual investment of £8.9 billion to 2030 being required.

The large investments are needed to deal with both changes in electricity generation and large increases in demand. In order to reduce carbon emissions from other sectors, many industries will have to switch to electric options (such as in transport and heating) leading to increasing demand. The Climate Change Committee, the independent body established to advise the government on climate change, estimates that new demands will mean demand rises by 50 per cent by 2035, and by 100 or 200 per cent by 2050.

This will correspond with a rise in the portion of production from low carbon sources and an increased need for storage. The rise of renewable sources and distributed energy resources

253 HM Government (October 2021), net zero Strategy: Build Back Greener, p. 338.
255 Climate Change Committee (December 2020), The Sixth Carbon Budget, p. 25.
needed to decarbonise the grid will lead to a more decentralised grid with the need for increased coordination across the different levels of supply.\textsuperscript{256}

NGESO has already published information on how they believe the system will evolve to cope with these challenges, at least in the short term. In their vision for 2025, NGESO discusses the new roles DSOs will have to undertake, with changes to market design in response to distributed energy and a much greater need for coordination with the ESO. This will see significant changes to the role of a DSO and the tasks they must take on.

As a result, separating DNOs and DSOs at this stage will likely come into conflict with the goal of achieving net zero. The changes needed to achieve net zero are major and present a major evolution for the role of the DSO. As discussed in Section 5.2 separating DNOs and DSOs would also create difficulties in coordination and come with major costs, and with an uncertain upside. These would only add to the difficulties that will be faced in the transition to net zero. Additionally, the costs faced when separating would also be on top of the investment needed to reach net zero, costs which would ultimately be passed onto consumers.

### 7.2. DSO Separation Would Absorb Resources and Time Needed to Achieve Net Zero

From the perspective of an economic welfare analysis, in which we assume there is no hard limit on resources that can be purchased by ESOs, DNOs and DSOs in the labour and factor input markets, there would be no theoretical reason to assume net zero cannot be achieved under any of the DSO separation models. However, this assumption may not be correct in reality. The government policy objective of achieving net zero will require enormous levels of investment and will absorb substantial human capital and therefore overall resource constraints must be considered to avoid putting at risk the objective of achieving net zero by the legally binding dates described above,

DSO-DNO separation would also require substantial one-off and on-going separation costs, as noted in Section 6.1.3, and would absorb resources (including staff within the DNO) that could be deployed on other aspects of meeting the net zero challenge. This suggests that business separation would be detrimental to achieving net zero due to the higher costs that would then be required to achieve this goal.

Of course, if it were the case that there were benefits to separation from the avoidance of a material and well-evidenced asset ownership bias, this argument would not hold, as the wasteful investment resulting from such a bias would also absorb resources. However, as explained in Section 6.3, no such evidence of inefficiency caused by an asset ownership bias exists. We accept this evidence may become available in the future, at which point Ofgem could reassess the need for separation, but at the moment it does not exist. There are also substantial costs associated with the new interface between the DNO and DSO that we have not considered quantitatively which would reinforce this conclusion. These costs, discussed in Section 6.4, include the costs associated with imperfect contracting, stringent oversight and regulation among other costs are likely to be significant and cannot be discounted.

Hence, the costs and resource requirement associated with business separation would distract DNOs, Ofgem and others in the industry from other challenges associated with achieving net

\textsuperscript{256} NGESO (2021), Enabling the DSO transition, p. 7.
zero, with no evidence that it would achieve a benefit. Enforcing and managing separation of DNOs and DSOs would place a significant regulatory burden among other costs, and given the benefits are uncertain to materialise, there is limited upside to separation.

There are also risks at the DNO-DSO interface that would result from business separation, that some outputs required by network users would be delivered to a lower quality. For example, as discussed in Section 5.2.1, neither party being responsible for reliability could result in a less dependable service as neither party is solely accountable for interruptions.

To the extent these outcomes are needed to achieve net zero, delays caused by DNO-DSO interface issues could hamper efforts to decarbonize and could take several years to fully resolve efficiently across industry. As explained above in Section 6.5, the risks from interface issues would be minimal under a ring-fencing option, as a single legal entity would be responsible for ensuring the delivery of services required by network users, and in this capacity could be held accountable. This includes in the delivery of new network capacity required to accommodate low carbon technologies onto the distribution network.

### 7.3. Any Business Separation Beyond Ring-Fencing Would Interfere with Achieving Net Zero

Therefore, considering the need to achieve net zero reinforces our conclusion above that there is no case for any business separation beyond ring fencing at this stage. The benefits of separation are too uncertain and the difficulties and costs involved with separation would serve as both a distraction as well as making the transition to net zero more costly. As concluded above, in this context ring-fencing as defined in this report may be a no-regrets option which keeps open the option for Ofgem and BEIS to pursue more significant vertical unbundling measures in the future if new evidence emerges regarding potential benefits of DSO separation.

Creating a net zero electricity grid requires significant changes and investment at all levels of electricity supply. There are challenges both in terms of the overall resource requirement needed to reach net zero, and the changes specific entities will need to make to deal with the differences of a net zero grid. Regarding DSOs, a net zero grid which is much more decentralised will require a greater degree of coordination with the ESO than is currently the case. The additional challenges of coordinating with the DNO would compound this issue if separation were to occur. The other costs involved with separation are also significant and would interfere with the goal of net zero.
8. Conclusions

In 2022 Ofgem will undertake a detailed review of DSO governance arrangements. Building on the separation of the system and network operator in transmission, there is now consideration of potentially extending this arrangement to distribution. In this report, we identify and assess alternative DSO governance models and provide an analysis of the cost and benefits associated with alternative DSO governance arrangements, as well as provide an overall welfare assessment of the different models and consider this in the context of net zero objectives. The report sits within the context of discussions by BEIS and Ofgem over future changes to the governance structure of DSOs, and provides evidence that can help inform these upcoming policy choices.

In our report, we undertake a quantitative analysis of the costs associated with DSO separation. We estimate a range for the costs for each DSO governance model (ring-fencing, legal unbundling, ownership unbundling and ESO amalgamation), as well as for different scopes of the DSO (Narrow, Wider and Widest). Our results show significant costs of separation, and the costs of separation rising with both the level of business separation and larger scope of the DSO.

Comparatively the benefits of separation are difficult to quantify and are far more uncertain. Therefore, we provide a more qualitative assessment of the potential benefits supported by economic theory. In distribution, we assess that the main potential benefit of separation to be the avoidance of both the existence and perception of an asset ownership bias, although this effect is likely to be small, no more than 1 to 2 per cent of avoidable expenditure. However, the extent to which this benefit would be realised depends on both the degree of separation and scope of the DSO. A greater degree of separation and a wider scope for the DSO means this bias is more likely to be avoided. However, greater separation and a wider scope is associated with higher separation costs. We also find that other benefits that have been identified to support the case for separation at the transmission level are not applicable in distribution, including for example avoiding distortions to competition in competitive procurement of networks.

Using our estimates for the cost of separation, we estimate the required cost savings that would be needed to offset the costs. For forms of separation beyond ring-fencing, the required benefits needed to offset the costs of separation are significantly higher than our estimate of 1 to 2 per cent of avoidable expenditure for the potential benefits. To justify legal separation or further, the cost savings stemming from the potential benefits would need to be greater than 4.2 per cent of avoidable expenditure, which we deem unlikely. As a result, the net welfare effects on consumers of further separation would likely be negative.

Therefore, following from our analysis, we recommend pursuing ring-fencing using a “wider” definition of the DSO. A narrower definition of the DSO would be too limited, avoiding the benefits of ring-fencing while the “widest” definition of the DSO would run the risk of creating operational difficulties in the DNO-DSO interface. Additionally, further separation of the DSO beyond ring-fencing would result in much higher costs and losses in vertical economies that are unlikely to be offset by any potential benefits, and overall result in high costs of separation and which may also undermine the objective of achieving net zero.
Appendix A. Literature Review and Precedent

A.1. Literature Review on the Loss of Vertical Economies

As discussed in Section 5.3.1 of this report, since the 1990s there has been extensive debate about the appropriate degree of vertical integration in the electricity and other infrastructure industries. Across all these industries, attempts to introduce competition in some parts of the value chain have led to concerns about the potential for vertical foreclosure and the advantages that vertically integrated incumbents might have over new entrants that are not involved in the natural monopoly parts of the value chain.

This policy debate has generated a vast body of economic literature that discusses the sources of economies of scope in the electricity sector and provides empirical evidence around the potential magnitude of the economies of scope from vertical integration.

A potential loss of vertical economies is the main cost associated with vertical unbundling. Vertical economies can be broken down into several different efficiency gains made by vertically integrated firms, such as better coordination, an avoidance of cost duplication, information symmetries among others.

Very little of this literature relates directly to the decision of whether and how to unbundle DSOs from DNOs. Nonetheless, this academic and policy literature provides evidence on the costs of unbundling and provides guidance on the extent to which there are economies of scope across different elements of the value chain that may be similar to those between the DNO and DSO.

Most of the studies reviewed in this report and further presented in this appendix use a cost function to estimate the economies of scope present in the electricity industry. Once the cost function is estimated, the degree of vertical economies is calculated following the general definition of Baumol et al. (1982) where the economies of scope $SC_T$ for producing a product $T$ are:

$$SC_T = \frac{[C(Y_T) + C(Y_{-T}) - C(Y)]}{C(Y)}$$

$C(Y)$ is the cost of producing the complete set of outputs $Y$, while $C(Y_T)$ is the cost of only producing $T$ and $C(Y_{-T})$ the cost of producing all products except $T$. As a result, the counterfactual in such a case is full separation of the production of different products. Therefore, in the papers presented below, the vertical economies estimated are those associated with full ownership unbundling relative to the status quo, rather than lesser forms of unbundling such as legal unbundling or ring fencing (unless otherwise stated).

A.1.1. Papers examining unbundling at different points in supply

In reviewing the results from past empirical studies, Meyer (2012a) separates the synergy losses by the type of unbundling considered. The excerpt below from Meyer (2012a) details the results from the literature review.

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Generation unbundling (GU) refers to a separation of the generation stage from the two network stages (transmission and distribution) and the retail function. This turns out to be the most costly unbundling option, since it increases both coordination costs and market risks. Focusing on the more recent studies, synergy losses can be range between 10 and 29 percent of total costs for medium sized companies. Distribution and retail unbundling (DRU) involves lower coordination losses, since generation and transmission remain vertically integrated. Accordingly, only distribution and retails are separated from the combined generation and transmission stage. This scenario leads to synergy losses between 4 and 13 percent. Similar results apply to pure network unbundling options. Both transmission unbundling (TU) and distribution unbundling (DU) only separate the respective network part from all other supply stages, resulting in synergy losses between 2 and 5 percent.\textsuperscript{258}

These distinctions between unbundling of different stages of the supply process have been used to group papers as seen in Table 5.4 of this report.

Meyer (2012a) also notes that coordination economies are the main source of scope, with a significant portion also seeming to come from a market risk affect (if generation and retail are separated).\textsuperscript{259} The interdependence between levels in supply means market players’ investment outcomes are dependent on other players at other levels of the supply chain. Investments are also highly specific and irreversible so investors are fully exposed to uncertainty and imperfect contracts (given the complexity of the industry) will mean that players face risks that may make them hesitant to invest.\textsuperscript{260} These risks can be reduced through vertical integration, increasing vertical economies.

Meyer (2012b) analyses a panel of US electric utilities data from FERC over a period from 2001-2008 using a quadratic cost function to estimate the economies of scope in electricity.\textsuperscript{261} Meyer finds that separating generation from retail results in an average cost increase of between 19 and 26 per cent. The economies of scope lost from separating generation and transmission from distribution and retail is estimated at between 8 and 10 per cent, and a split between transmission and the remaining stages of supply is estimated at 4 per cent.\textsuperscript{262}

Meyer (2011) uses a bootstrapping data envelopment analysis (DEA) to analyse the economies of vertical integration in US electricity. Meyer finds that separating generation from retail raises costs by 19 per cent while unbundling transmission, as has been done in the


EU under the Third package raises costs by less than 2 per cent. Again, Meyer uses the FERC dataset covering US electric utilities from 2001 to 2008.

A.1.2. Papers examining unbundling of generation from transmission, distribution and retail

Arocena et al. (2012) estimate mean vertical economies of 8.1 per cent of total costs when analysing generation and distribution of electricity in the US, with data from 116 Investor Owned Utilities in the US from 2001. The counterfactual under different levels of unbundling is not analysed, with the savings due to vertical economies under the status quo being the focus of the analysis. The results show vertical integration is a more efficient organisational form in electricity compared to leaving vertical supply to the market. Arocena et al. (2012) use a quadratic cost function with a flexible functional form (so it can provide a second order approximation of any functional form) to estimate the economies of scope.

Arocena et al. (2009) uses a quadratic cost function to estimate the economies of scope on a sample of investor-owned utilities from 2001. They find that the economies of scope from unbundling generation is between 4 and 10 per cent, with the results matching closely with those found in Arocena et al. (2012).

Kaserman and Mayo (1991) represents one of the earlier papers empirically looking at sources of vertical economies. Kaserman and Mayo use a flexible fixed cost quadratic cost function to estimate the economies of scope (although the cost function includes less control variables than later papers). Working with US data from 1981, they find that vertical economies reduce costs by between 19 and 54 per cent. It is also found that very small firms do not show vertical economies.


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Fetz and Filippini (2010) analyse the presence of economies of scale in the Swiss electricity sector, using a panel dataset of 74 companies from 1997-2005 to look at the economies of scope between electricity production and distribution. Using a quadratic, multistage cost function, Fetz and Filippini find that vertical integration between electricity production and distribution reduced transaction costs, resulted in better coordination of specific and interdependent investments, and reduced financial risk. They find significant vertical economies of over 40 per cent, although this could be due to a small sample size and small number of customers for each company.

Mydland et al. (2020) look at the increase in costs due to vertical economies that arise when separating generation and distribution companies. Mydland et al. use data collected from 2004 to 2014 on 212 Norwegian electricity companies. Closely following the approach taken by Triebs et al. (2016), Mydland et al. use a flexible cost function to estimate the economies of scope for 90 per cent of the firms in the sample falling between minus 8 per cent and 53 per cent (50 per cent between 2 per cent and 21 per cent and median of 10 per cent). It is found that economies of scope decline with firm size.

### A.1.3. Papers examining unbundling distribution and retail from generation

Arocena (2008) uses a DEA approach to estimate the cost reduction due to vertical integration of generation and distribution. The data used is a panel of Spanish electric utilities from 1989 to 1997, with results suggesting vertical economies lost from unbundling distribution from retail are between 4 and 5 per cent.

Fraquelli et al. (2005) look at a sample of Italian municipal utilities from 1994 to 2000 (with some being vertically integrated and others being distribution only). Using a composite cost function, Fraquelli et al. show significant vertical economies rising from 3 per cent up to 40 per cent, with larger firms seeing greater vertical economies.

Jara Diaz et al. (2004) also work with data from the Spanish electricity sector. The data used runs from 1985 to 1996 looks at the 12 most important generation and distribution firms in Spain at the time, finding that the vertical economies of distribution and retail unbundling sit at around 8 per cent and joint generation and distribution saving 6.5 per cent. Jara Diaz

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274 Mydland, O. et al. (2020), Economies of scope and scale in the Norwegian electricity industry, *Economic Modelling*, p. 44.


uses a quadratic cost function and factor share expressions to estimate the economies of scope.\textsuperscript{279}

\textbf{A.1.4. Papers examining unbundling transmission and generation}

Triebs et al. (2016) look more widely at a panel of US publicly owned electric utilities from 2000-2003. Using a flexible cost function, Triebs et al. look at the increase in costs associated with separating transmission of electricity and generation. Their results suggest more modest economies of scope, with cost savings of 4.4 per cent.\textsuperscript{280}

Gugler et al. (2017) examine the scope of vertical economies in European electricity transmission, examining the costs associated with separating transmission from other stages of supply. Gugler et al. use a full specification of the cost function, with a full set of interaction terms to estimate the degree of vertical economies.\textsuperscript{281} Looking at data from 2000-2010, they find substantial cost savings from vertical integration, with a cost saving of 14 per cent for the median integrated utility (compared to fully unbundled).\textsuperscript{282} They also find that cost savings rise with firm size, due to large variable cost synergies.\textsuperscript{283} However, other studies have found the opposite result, with smaller firms benefitting more from vertical economies.\textsuperscript{284}

Overall, the literature shows that the size of the vertical economies is not constant. Size, corporate form, geographical location and regulatory framework can affect the size of the vertical economies\textsuperscript{285} which can help explain the large variation seen in the estimate of the size of vertical economies.

\textbf{A.2. Precedent from Previous Impact Assessments on the Separation of Functions and Roles from National Grid}

\textbf{A.2.1. The ESO legal separation impact assessment}

In 2017, BEIS, Ofgem and National Grid issued a joint statement of intent proposing changes to the role of Electricity System Operator (ESO), proposing that a separation between National Grid’s ESO and transmission owner (TO) functions would make industry confident

\begin{itemize}
  \item For example, Mydland, O. et al. (2020), Economies of scope and scale in the Norwegian electricity industry, \textit{Economic Modelling}, p. 44.
\end{itemize}
in its impartiality and would mitigate actual/perceived conflicts of interests. Following that, in April 2019, the ESO was legally separated within National Grid plc.

The objective of the ESO legal separation was to enhance the independence and transparency of the ESO, and to mitigate any actual or perceived conflict of interests. Before the legal separation of ESO, National Grid already had separate SO business, but legal separation took a step further in providing the ESO its own licence, separate from the electricity transmission owner, and its own board of directors. In particular, the ESO legal separation resulted in the following:

- **Governance structure**: The NG ESO is governed by a separate Board of Directors. The board consists of three National Grid directors, three independent directors, and one chair of the National Grid director. ESO board members are allowed on the National Grid board or boards of other NG electricity companies. Additionally, NG has established a Compliance Committee.

- **Financial requirements**: The ESO has its own separate accounts to avoid cross-subsidies between the ESO and any other National Grid Group entities. However, the National Grid group provides the ESO with assistances on debt management, working capital arrangement, and potential financial assistance.

- **Operational separation**: Consists in the separation of the ESO’s licence from the other licensed entities within National Grid, including National Grid Electricity Transmission, National Grid Gas, the licensee for the combined gas system operator and gas transmission owner, and non-regulated business, like electricity interconnection.

- **Information ringfencing**: To enable the ESO to continue to operate effectively as well as comply with the “System Operator Functions Information” (SOFI), the ESO has updated its systems and unstructured data with appropriate access controls and restrictions, reviewed and redesigned its employees on the new obligations. Sharing of information between ESO and other NG parties is allowed in specific, legitimate circumstances, with necessary controls to protect SOFI.

- **Employee separation, incentivisation and transfer**: ESO staff are employed by NG ESO and ESO managers are incentivised on ESO metrics. Staff is incentivised on the performance of SO only. There is business separation training for employee and employee transferring to other National Grid entities is reviewed by Business Separation Compliance Officer to determine whether special measures are needed to maintain compliance.

- **Physical separation**: NG ESO has been relocated within a physically separated wing of National Grid’s existing headquarter, with separate entrance and staff facilities.

- **Shared services**: Transactional services continue to be shared between NG ESO and the other National Grid entities, while strategic services are shared under a business partner arrangement to deliver the strategic activities.

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287 NGESO (July 2020), National Grid Electricity System Operator Business Separation Compliance Statement, p. 3-4.
• **Culture & branding**: The NG ESO has adopted a distinct and explicit visual identity from the National Grid, including physical appearance through new logos, imagery and colour palettes and the way its employees present and identify themselves.

### A.2.1.1. Allowed upfront and on-going costs of the ESO legal separation

Ofgem assessed the costs and benefits of legal separation against a ‘do nothing’ counterfactual scenario. The counterfactual assumed the continuation of existing arrangements with NGET undertaking both SO and TO responsibilities, and the independent SO not taking forward any new roles.

As part of the process, National Grid submitted its estimates of the one-off and on-going costs of separation costs to Ofgem. Over the course of the process, National Grid’s cost submission increased from £46.5 million to £54.8 million for the upfront costs, and from £6.5 million per year to £8.5 million per year for the on-going costs (2016/17 prices)\(^{288}\), including additional ESO and Gas System Operator (GSO) separation costs of £4.8 million in 2016/17 prices (one-off costs) and £1.8 million per year (on-going costs).\(^{289}\) The increase reflected a National Grid’s better understanding of the actual costs involved with separating the ESO and the stronger separation requirements between electricity and gas.

Ofgem reviewed National Grid’s cost submission and provided its estimate of the one-off costs of separation of £49.3 million and on-going costs of separation of £9.1 million per year (2016/17 prices).\(^{290}\) Ofgem also estimated £1m one-off implementation cost that Ofgem itself would incur.\(^{291}\) The costs submitted by National Grid and Ofgem’s allowances are set out in Table A.1.\(^{292}\)

In reviewing the costs of separation, Ofgem acknowledged that there may be a risk of losing or diminishing synergies between the SO and TO functions after separation. Ofgem noted that separation may have a negative impact on consumers benefit from having one single party planning, delivering and balancing the E&W network.\(^{293}\) However, Ofgem does not quantify the value of losses in operational synergies.

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289 Ofgem (2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, Appendix 2, Table 2.

290 Ofgem (2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, Appendix 2, Table 2. Costs for ESO/GSO separation included.


292 Ofgem (2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, Appendix 1, Table 2.

Table A.1: National Grid’s Submission and Ofgem’s Assessment of ESO Separation Costs

<table>
<thead>
<tr>
<th>Previous Category</th>
<th>Category</th>
<th>Cost</th>
<th>Commentary</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>UpFront Cm</td>
<td>Enduring Annul</td>
<td></td>
</tr>
<tr>
<td>Business Change</td>
<td>WL, SO/TO Boundary Design</td>
<td>3.1</td>
<td>2.8</td>
</tr>
<tr>
<td></td>
<td>WL, People &amp; Process Readiness</td>
<td>2.1</td>
<td>2.1</td>
</tr>
<tr>
<td></td>
<td>WL, Process Readiness</td>
<td>9.1</td>
<td>9.4</td>
</tr>
<tr>
<td></td>
<td>WL, Regulated and Contractual Change</td>
<td>2.6</td>
<td>2.3</td>
</tr>
<tr>
<td></td>
<td>WL, Project Management &amp; Business Assurance</td>
<td>0.07</td>
<td>0.09</td>
</tr>
<tr>
<td></td>
<td>Programmes Management &amp; MA</td>
<td>4.7</td>
<td>4.9</td>
</tr>
<tr>
<td></td>
<td>Conformance</td>
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<td>0.3</td>
</tr>
<tr>
<td></td>
<td>Total Business Change Sub-Total</td>
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<td>25.5</td>
</tr>
<tr>
<td>Information Services (IS)</td>
<td>IS Technology &amp; Data</td>
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<td>2.4</td>
</tr>
<tr>
<td></td>
<td>IS Non-Operational IS &amp; Data</td>
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<td>0.6</td>
</tr>
<tr>
<td></td>
<td>Total IS</td>
<td>3.2</td>
<td>3.0</td>
</tr>
<tr>
<td>Buildings</td>
<td>WL, Property</td>
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<td>3.3</td>
</tr>
<tr>
<td></td>
<td>WL, Finance, Pricing, Accounts &amp; Regulation</td>
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<td>0.7</td>
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<td></td>
<td>WL, Regulation &amp; Incentives</td>
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<td>0.0</td>
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<td></td>
<td>Total Financial</td>
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<tr>
<td>Enduring Governance</td>
<td>WL</td>
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<td>0.7</td>
</tr>
<tr>
<td></td>
<td>No Change</td>
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<td>0.4</td>
</tr>
<tr>
<td></td>
<td>Total Enduring Governance</td>
<td>1.5</td>
<td>1.1</td>
</tr>
<tr>
<td>Enduring Staff</td>
<td>WL, IS</td>
<td>6.5</td>
<td>4.7</td>
</tr>
<tr>
<td></td>
<td>IS Operations</td>
<td>0.3</td>
<td>0.2</td>
</tr>
<tr>
<td></td>
<td>Total Enduring Staff</td>
<td>6.8</td>
<td>5.7</td>
</tr>
<tr>
<td></td>
<td>Total Enduring Staff Sub-Total</td>
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<td>10.5</td>
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<tr>
<td></td>
<td>Total</td>
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<td>28.0</td>
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<td>Business Support</td>
<td>Economic Support</td>
<td>5.3</td>
<td>5.8</td>
</tr>
<tr>
<td></td>
<td>Economic and Efficient Costs for new staff</td>
<td>0.8</td>
<td>0.6</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>5.6</td>
<td>5.6</td>
</tr>
<tr>
<td>Additional ESO/TO separation</td>
<td>ESO/TO Separation</td>
<td>4.8</td>
<td>4.8</td>
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<tr>
<td></td>
<td>Economic and Efficient Costs for new staff</td>
<td>1.8</td>
<td>1.8</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>4.8</td>
<td>4.8</td>
</tr>
</tbody>
</table>

Source: Ofgem.

A.2.1.2. Ofgem’s assessment of potential benefits from the SO and TO separation

Ofgem performed a qualitative assessment of the potential benefits from the ESO legal separation, identifying the following potential areas of benefit:

- Ofgem noted that the separation of SO with its own governance structure and employee would mitigate the risk of bias towards NGET’s other business interest.294

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• Ofgem expected separation to ensure sufficient independence of the SO to oversee the whole system and to deliver the best overall outcome for consumers.295

• Ofgem assumed separation could lead to significant improvements to competition and efficiency in the industry. 296

• Ofgem considered that separating the ESO from the NGTO company would promote innovation and provide a route for new players and business models to emerge. 297

A.2.1.3. Aggregate consumer impact and switchover analysis

As noted above, Ofgem did not quantify the benefits of separation, since the benefits would be very difficult to quantify robustly. Instead, Ofgem performed a switchover analysis aimed at determining “the efficiency savings that would be required in network investment and balancing costs to offset the expected costs” of its separation proposals.298 Using this approach, Ofgem established that the benefits are likely to significantly outweigh the costs.299

Ofgem stated that “We think consumers will be the ultimate beneficiaries of our proposals, principally through mitigating conflicts of interest and through greater industry confidence, which should encourage more investment and drive efficiency.”300 Ofgem considered that future consumers may stand to gain somewhat more than present consumers as the full benefits of these changes may take some time to come through.

Overall, Ofgem assessed that to offset the total cost of separation (equal to £216.67 million in 2016/17 prices in NPV terms over 30-year period), the ESO legal separation would need to deliver a 0.22 per cent efficiency saving through combined transmission and distribution network investment, and balancing costs over the 30-year period.301

A.2.2. The impact assessment for Future System Operator (FSO)

Following the legal separation of NG ESO in April 2019, BEIS and Ofgem are considering establishing a fully independent future system operator (FSO). In July 2021 Ofgem and BEIS published a joint consultation document on the FSO, including an impact assessment of the cost and benefits of alternative options for establishing an FSO.

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301 Ofgem (2017), Future Arrangements for the Electricity System Operator: Response to Consultation on SO Separation, Appendix 2, para. 1.43.
Appendix A

BEIS and Ofgem stated that an independent FSO with responsibilities in both the electricity and gas systems would be better positioned to perform whole systems planning and government advisory roles. For the electricity roles of the FSO, BEIS and Ofgem propose that all the current National Grid ESO roles and functions to be carried out by the FSO, due to the synergies between balancing the electricity system and analysing its future needs.\(^\text{302}\)

**A.2.2.1. Candidate FSO options considered by BEIS and Ofgem**

BEIS/Ofgem appraised three options against the “Do nothing” scenario. The do-nothing counterfactual reflects the existing SO structures but reflecting the changes that Ofgem plans to implement on NG ESO in RIIO-2 period (2021-26) around measures to mitigate conflicts of interest. Table A.2 summarises BEIS/Ofgem’s candidate FSO options and the corresponding roles for the ESO and GSO under each.\(^\text{303}\)

### Table A.2: Roles of FSO under Different Level of Separation

<table>
<thead>
<tr>
<th>Option</th>
<th>Electricity Roles</th>
<th>Gas Roles</th>
</tr>
</thead>
</table>
| **Option 1** “lower intervention” | • Real time system balancing of the electricity system  
• Undertakes advisory, enhanced planning and competition roles (coordinated network planning, enhanced NOA process, and running tenders for electricity network competition) | • No formal roles  
• Long-term forecasting and some strategic gas functions capabilities will be built within the FSO |
| **Option 2** “preferred way forward” | • Roles in option 1  
• Coordinating elements of heat and transport decarbonisation. For example, in local energy mapping and planning.  
• Coordinating across organisations (DNOs, TOs, gas networks and government departments)  
• Functions in energy code governance, engineering standards and data | • Network capability planning (which could be formalised into a Gas Network Options Assessment process analogous to that already performed by NGESO for electricity networks) and  
• Strategic capability assessment for new connections, asset replacement and decommissions; and  
• Medium to long-term forecasting |
| **Option 3** “greater intervention” | • Same as option 2 | • Roles in option 2  
• Control room functions, including day-to-day network balancing, operational planning and both emergency response and outage co-ordination |


\(^{302}\) BEIS & Ofgem (July 2021), Future of the System Operator Consultation, p. 11.

A.2.2.2. The upfront and on-going costs of separation

Ofgem’s and BEIS’s impact assessment on the costs and benefits of a new FSO does not rely on actual cost data submitted by National Grid, but relies on internal estimates from BEIS/Ofgem project budgets as well as analysis from FTI Consulting performed for Ofgem. The timeframe for the impact assessment is 2022-2050.

The impact assessment of new FSO identifies the following areas of costs:304

- **Capital cost of implementation**: BEIS/Ofgem expect there to be a significant amount of capital costs associated with the establishment of new FSO, but do not publish the associated data because commercially sensitive.

- **Cost of implementing the FSO**:
  - **Legal, financial and consultancy costs**: Include including legal, financial and consultancy costs incurred to implement separation.
  - **One-off separation costs**: One-off project costs National Grid and future owner of the FSO need to incur in separating the ESO / GSO roles, such as recruitment, property and IT systems separation costs incurred in separation; and
  - **On-going costs**: Ongoing costs National Grid and the future owner of the FSO need to incur following separation. These may include the costs of additional personnel for roles that are currently shared, duplicate licences for IT and technology, and duplicate services.

To estimate both on-going costs and one-off costs of separation, BEIS/Ofgem rely on the estimates provided by FTI for Ofgem. BEIS/Ofgem assesses that there would be additional on-going costs for full ownership separation of the ESO based on FTI’s analysis ranging between £2 and £4 million year.305 The on-going costs of GSO separation are not reported separately. BEIS/Ofgem assume on-going costs to be incurred as from 2024 and throughout the modelling horizon at a constant rate (i.e., 2022-2050).

Regarding one-off costs of separation, BEIS/Ofgem assume one-off costs of £22 million under all options based on FTI’s analysis. For gas roles, BEIS/Ofgem assume that the one-off GSO costs of £100 million range depending on the scope of the gas roles taken by the FSO: from 1 per cent if the FSO does not have a formal gas role (option 1), to 20 per cent if the FSO is responsible for gas network planning only (option 2), and up to 100 per cent if the FSO performs all day-to-day operations and all supporting functions (option 3). BEIS/Ofgem assume legal, financial and consultancy costs to be incurred between 2020-2025 whilst the separation costs take place between 2024-2026 and are spread evenly over the three years.

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A.2.2.3. Loss of synergies

BEIS/Ofgem assumes that any operational synergies between NGESO and the TO has already been lost in the 2019 NGESO legal separation. Though uncertainties remain, BEIS/Ofgem consider that there is no further loss of operational synergies from the electricity roles.\(^{306}\)

For the gas roles, BEIS/Ofgem assume that if the GSO and GTO were to separate the control room, the GTO would be less responsive on the GSO requests. Consequently, the GSO would have to take more commercial actions instead of relying on the operational actions from the GTO. Based on an FTI’s case study on the real-world oversupply event at Milford Haven in 2016, \(^{307}\) BEIS/Ofgem assume the GSO would take around 3 actions per year, compared to an historical average of 0.4, \(^{308}\) which would result in between £70 million to £420 million (2019/20 prices) losses of operational synergies. \(^{309}\)

BEIS/Ofgem’s impact assessment also considers the non-monetised communication and learning costs of separation. BEIS/Ofgem assess that there would be non-monetised cost associated with increased needs of communication and collaboration between the FSO and TO, especially for the previously integrated gas roles. \(^{310}\) In addition, BEIS/Ofgem note that the FSO, TO, the regulator and other relevant stakeholders are expected to incur learning costs for familiarising with the new structure and process. \(^{311}\)

A.2.2.4. Benefits of establishing the independent FSO

BEIS/Ofgem consider that benefits of establishing the new FSO mainly come from the following aspects:

- **Reduce potential conflicts of interest and improve ‘whole systems’ decision making:** BEIS/Ofgem note that the new FSO could reduce the perceived conflict of interest and deliver a “whole systems” approach to network development and assessing energy system needs. According to BEIS/Ofgem, the removal of potential conflict of interest would enable the FSO to take on enhanced roles and responsibilities which would help to ensure


\(^{311}\) BEIS & Ofgem (July 2021), Energy Future System Operator Consultation: Impact Assessment, para. 73.
that decisions made across the system work together to meet decarbonisation and security of supply goals at least cost.  

To quantify the benefits from removing conflict of interest and improving “whole system” planning, BEIS/Ofgem take the following steps. First, they forecast the electricity and gas TO’s totex over 2050 across a range net zero compatible scenarios. Then, noting that it difficult to quantify the extent of the benefits, they assume an illustrative proportion of 1 to 5 per cent of total expenditure to be saved from improved whole systems decision making and removal of conflicts of interest.

As a result, they estimate the saving from “whole system” planning to be £210 million to £2500 million in NPV terms (in 2020 price base) for electricity, £50 million to £300 million in NPV terms (in 2020 price base) for natural gas, and £30 million to £300 million for hydrogen in NPV terms (in 2020 price base).

- **Improved facilitation of network competition (electricity only):** BEIS/Ofgem assess that an independent FSO may result in improved facilitation of network competition because of the following:
  - The increased perception that the FSO is impartial may increase participation in competitions and likely reducing costs;
  - The enhanced powers taken on by the FSO may enable more opportunities for competition to be identified and realised; and
  - Better decisions may be made on the location, timing and design of competitions by removing the potential conflicts of interest that currently exist.

To quantify the benefits from facilitating network competition, BEIS/Ofgem first look at the total cost savings in transmission network development that are expected to occur due to competition, then assume that a proportion of these benefits from competition is lost due to the perceived or actual conflict of interest under the current SO.

Information from a 2016 Impact Assessment on the potential for onshore electricity network competition suggests that net cumulative benefits from competition are between £300 million to £600 million in NPV terms (2020 price base). Since proportion of benefit lost due to perceived conflict of interest is hard to estimate, BEIS/Ofgem consider an illustrative proportion between 25 per cent and 50 per cent, in line with FTI analysis. This provides an estimate of benefits from introduction network competition in electricity between £75 million and £300 million in NPV terms.

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316 DECC & Ofgem (January 2016), Extending competitive tendering in the GB electricity transmission network.
However, for the gas system, BEIS(Ofgem) do not assume any competitive procurement in the gas transmission network noting that any proposals to introduce this would be “speculative”.

BEIS and Ofgem conclude that the net present values are positive for all three options considered for electricity, with the primary benefit being the reduced electricity system costs from “whole system” planning. However, BEIS and Ofgem find it is more costly to separate the gas roles and there would be smaller benefits from a separation, given that the GSO and GTO are more integrated and there would be declining usage of natural gas to generate significant value from separation. BEIS and Ofgem hence conclude that the cost of separation will outweigh the benefits achievable for the gas roles in option 3. 318

A.2.3. Impact Assessment on separation measures for the EMR within National Grid

In October 2013, when the SO was still an integrated business unit within National Grid and the delivery body of the Electricity Market Reform (EMR), there were concerns on potential conflicts of interest between the EMR role and National Grid’s existing roles.

As the Department of Energy and Climate Change (DECC) noted: “this could occur via an asymmetry of information that exists between Government and National Grid (through its role as the EMR delivery body). The exploitation of these information asymmetries could lead to sub-optimal delivery of EMR and an inefficient allocation of resources, resulting in welfare losses to society. The perception of conflicts of interest could also reduce investor confidence in EMR and put at risk the investment required to meet EMR’s objectives.” 319

Hence DECC considered several options to mitigate the potential conflicts of interest between the EMR and SO/TO and conducted an impact assessment to assess the costs and benefits in relation to each option.

A.2.3.1. Relevant separation measures for the EMR function

Among the total five options DECC considered in the impact assessment, there were three options which are helpful for our assessment of the DNO/DSO separation, namely: 320

- **Legal separation of EMR functions:** Separating the EMR functions from the combined SO/TO business. Under this option, there is legal separation between the EMR and SO.

- **EMR Ring-fencing:** Keeping EMR integrated with the SO functions within which there are most important synergies, while separating remaining functions to reduce risk of conflicts. Under this option, the SO retains the EMR function with necessary ring-fencing measures.

- **Separation of the SO:** Legal separation of the SO and EMR functions from the remaining TO functions.


319 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, p. 1.

320 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, p. 1.
A.2.3.2. Cost assessment of different separation measures

DECC quantified the cost against the “do nothing” option, which assumed the status quo for the EMR structure and regulatory framework.

To quantify the cost under EMR legal separation option, DECC conducted a bottom-up approach to estimate up-front cost of separation. Based on DECC’s understanding on the set up of EMR function, and discussion with National Grid and Ofgem, DECC assessed the costs of information separation, employee separation, as well as physical, legal and financial services. It estimates the one-off set up costs to be within the range of £0 - £29m (2010 prices).  

For ongoing costs of the EMR legal separation, DECC assessed the cost of staff, IT system and premises. The ongoing costs DECC estimated for the EMR legal separation is £8 million per year (2010 prices).  

DECC carried out similar analysis for the EMR ring-fencing option and estimated the upfront costs to be £0 - £0.049 million (2010 prices) with on-going costs from £0.78 million - £2.5 million (2010 prices).

To estimate cost for the separation between the SO and TO, DECC looked at the Ofwat report for potential costs of separation of retail water. In the report, Ofwat cited precedent cases on separation costs: including separation of the water business companies in Scotland, separation of the Public Electricity Suppliers (PES) in the UK, and creation of Openreach by BT. Table A.3 shows the DECC’s summary of Ofwat report.

Table A.3: Evidence on Costs of Legal separation for Large company (1 Million Billed households,1,000 Employees)

<table>
<thead>
<tr>
<th>Type of separation</th>
<th>Total costs (£m)</th>
</tr>
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<tr>
<td></td>
<td>Transitional costs</td>
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<tr>
<td></td>
<td>Low</td>
</tr>
<tr>
<td>Legal</td>
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</tr>
</tbody>
</table>

Source: DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, Table E1

Based on Ofwat analysis, National Grid’s forecast of customer numbers and data on numbers of gas and electricity business meters, DECC extrapolated the legal separation and functional separation costs for National Grid SO, using the per customer costs shown in Table A.4.

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321 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 104.

322 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 106.

323 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 124.
Table A.4: Separation Cost per Household

<table>
<thead>
<tr>
<th>Type of separation</th>
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</thead>
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<tr>
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<td>costs</td>
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<td>Functional</td>
<td>0.8</td>
<td>1.59</td>
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</table>

Source: DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, Table E3

DECC estimated the one-off legal separation costs to be £1.21 - £2.44 per customer and ongoing cost of £0.5 - £1.1 (2010 prices), with the total one-off cost to be between £40 and £82 million (2010 prices) and recurring costs to be between £17 and £37 million per year (2010 prices).\(^{324}\) DECC estimated the one-off functional separation costs to be between £0.8 and £1.59 per customer and ongoing cost of £0.21 - £0.33 (2010 prices), with the total costs of functional separation be equal to £27 - £53 million for the one-off costs (2010 prices) and between £7 to £11 million per year for the on-going costs (2010 prices).\(^{325}\)

A.2.3.3. Loss of operational synergies

DECC identified potential losses of synergies but considered they are non-quantifiable costs. On top of operational synergies, DECC identified two additional sources of synergies, including system synergies created through delivering the EMR function that would allow for better whole system planning for the SO and TO; and analytical synergies that come from leveraging expertise and information from SO/TO roles to improve EMR outcomes.\(^{326}\)

The potential losses of synergies DECC identified for various options are as follows:

- For the EMR legal separation option, DECC assessed that operational synergies between EMR function and SO would be lost, though there would still be some legal, HR, and IT services shared between the two functions. Most of the system synergies between the EMR function and the SO would be lost. Some analytical synergies could be preserved, since information could still flow from the SO to the EMR.\(^{327}\)

- For the EMR functional separation option, DECC assessed that majority of key synergies would be retained by the EMR and SO. Only some analytical synergies relating to the ‘administrative’ functions, for example, allocation of Capacity Market auctions, would be lost to some extent.\(^{328}\)

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\(^{324}\) DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 181.

\(^{325}\) DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 181.

\(^{326}\) DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 185.

\(^{327}\) DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 112.

\(^{328}\) DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 126.
• For the SO and TO legal separation option, DECC suggested that the synergies between the EMR and SO roles would be retained under this option, however, analytical synergies that require input from TO would be lost, and system synergies that would allow better planning for TO would be lost. In addition, DECC assessed that there would be losses of synergies between the SO and TO, but considered these synergies were not within the scope of the EMR impact assessment.329

A.2.3.4. Benefits

To quantify benefits of each option, DECC relied on a report prepared by KPMG on the potential benefits from avoiding conflicts of interest. KPMG assessed the probability of each conflict arising and the likely impact, in terms of additional profit for National Grid of exploiting such a conflict and associated resource cost to society. KPMG concluded:

• The probability of National Grid acting on all identified conflicts of interest is low, and assigns a probability of 0 – 33 per cent.330

• The potential additional profits for National Grid from acting on the conflicts of interest are around £50 million - £70 million in NPV terms.331

Using KPMG’s analysis, DECC applied a ‘best estimate’ probability of 5 per cent for the probability of National Grid acting on any conflicts of interests and estimated costs to society from National Grid acting on its conflicts.332 Based on this analysis DECC concluded that:

• Under the EMR legal separation, all potential conflicts of interests would disappear. It estimated the potential benefits range between £0 - £1,140 million (2010 price base), with a best estimate of £173 million (2010 price base).333

• For the EMR ring-fencing option, DECC noted that if assuming ring-fencing is fully effective, then the ring-fencing option can achieve all the benefits under the EMR legal separation. Though it is likely that the ring-fencing might be less effective at mitigating conflicts than EMR legal separation.334

• For the benefits for TO and SO legal separation, DECC estimated that the potential benefits range between £0 - £1,140 million (2010 price base), with a best estimate of

329 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 93.

330 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, Appendix C, para. 150-152.

331 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, Appendix C, para. 155.

332 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, Appendix C, para. 153. According to DECC report footnote 17, Resource costs relate to the capex costs of new network and generation capacity, in addition to the generation and carbon costs associated when operating the generation capacity relative to a base case scenario.

333 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 100.

334 DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 120.
£173 million (2010 price base).³³⁵ In addition, DECC considered that there would be benefits and costs from existing conflicts of interest and synergies between the SO and TO. However, DECC did not take these effects into account given the scope of the study.³³⁶

A.2.3.5. Conclusions

Table A.5 summarises the monetised costs and benefits of the alternative separation options.

<table>
<thead>
<tr>
<th>Option</th>
<th>Best estimate of Present Value, £m (2014-2030)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Costs</td>
</tr>
<tr>
<td>Legal separation of SO</td>
<td>334</td>
</tr>
<tr>
<td>Legal separation of EMR</td>
<td>64</td>
</tr>
<tr>
<td>EMR ring-fencing</td>
<td>19</td>
</tr>
</tbody>
</table>

Source: DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, Table B.

³³⁵ DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 88.

³³⁶ DECC (October 2013), Impact Assessment of measures to address potential conflicts of interest arising in relation to the choice of National Grid as the delivery body for EMR, para. 89.
Appendix B. Detailed Analysis of Duplication of Overheads

In Section 5.3.3 we have assessed the extent of duplication of business support costs following DNO and DSO separation and which can provide a proxy for the on-going costs of separation. We rely on DNO sector level data to estimate these costs as explained in the remainder of this appendix.

B.1. Econometric Analysis on Duplicated On-Going Fixed Costs

At RIIO-ED1, Ofgem assessed business support costs (BSC) using a unit-cost or ratio approach. Ofgem assumed that DNOs’ BSC were determined on a £ per unit DNOs’ Modern Equivalent Asset Value (MEAV). This approach therefore assumed no economies of scale and zero fixed cost. Under this assumption, the business support costs are purely variable costs that grow proportionately with the size of a business, hence would not be affected by the DNO and DSO separation.

At RIIO-T2 Ofgem commissioned consultants ECA to perform a regression analysis of the transmission companies’ BSCs. ECA considered a number of alternative functional forms, but recommended approach using a logarithmic form of cost and driver variables. The coefficients of this functional form estimate the elasticity of cost to the corresponding driver, i.e., they measure the percentage increase in costs associated with 1 per cent increase in the associated cost driver. ECA considers size drivers including revenue, total spend, employees, network length and MEAV.

However, whether this assumption holds is questionable, as it is reasonable to expect a DNO to incur some upfront business support costs which are invariant to scale (i.e., these costs are fixed). Such costs would be duplicated if the DNO were split into two.

To assess the degree to which DNOs’ BSCs contain fixed costs that would be duplicated, we have performed several Ordinary Least Squares (OLS) regressions that use a linear functional form:

- We have not used Ofgem’s ED1 approach of unit cost modelling, because this assumes (rather implausibly) that no element of DNOs’ BSCs are fixed in nature and invariant to scale or the level of workload being performed by DNOs. Hence, we cannot identify the fixed costs that would be duplicated on separation.
- Similarly, we have not used a log-linear approach like ECA at T2. While the log-linear functional form is widely used in econometric cost modelling, in this case we are primarily interested in the fixed costs, identifiable by assessing what BSCs DNOs would incur if their drivers took a value of zero within a regression equation. Log-linear models

---

337 MEAV is calculated by multiplying the number of assets DNOs have in each cost category (e.g. overhead pole line, and overhead tower line), multiplied by an assumed unit cost of a “modern equivalent” of these assets. In essence, it reflects the replacement cost of the network, and is designed to act within Ofgem’s benchmarking as a proxy for the scale of DNOs’ operations. Source: Ofgem (December 2014), RIIO-ED1: Final determinations for the slow-track electricity distribution companies: Business plan expenditure assessment, p. 130.

338 Ofgem (June 2019), RIIO-2 tools for cost assessment, p. 17.

339 Ofgem (June 2019), RIIO-2 tools for cost assessment, p. 49.
do not lend themselves to estimating this, because the equation cannot be evaluated at a zero value for a driver.\footnote{Logarithmic models assume a proportional relationship between costs and drivers. In the model $\ln(\text{Cost}) = a + b \times \ln(\text{Driver})$, the coefficient $b$ is an elasticity, characterising the percentage change in costs following a percentage change in the driver. However, the natural logarithm of a driver tends towards negative infinity as the value of the driver tends towards zero. Hence, this functional form does not provide useful information for the current purpose.}

Instead, our regressions use a linear functional form to test whether we find a statistically significant constant term that would indicate that there are fixed business support costs that do not vary with scale. These fixed costs would therefore need to be duplicated upon separation of the DSO and DNO.

**B.1.1. Data**

We use cost data for the 14 licensees over the DPCR5 and ED1 control periods to date using data reported in the 2020-21 RRPs and adjusting all values to be in 2020/21 prices. We consider total business support costs, including therefore the costs under the following RRP categories: C12 core BS, C13 IT&T (BS), and C14 property management (BS).

We have conducted the analysis using DNO data at both the group and licensee level. At the group level, this means we sum up the data of individual licensees that belong to the same group and perform regression analysis on the sample of 6 groups over the DPCR5 and ED1 control periods, using the historical data available up to 2021, based on information in the 2020/21 RRPs. In the licensee regressions we have more data points, as each of the 14 licensees is represented separately.

**B.1.2. Selection of cost drivers**

We identify scale variables that we consider to be good proxies of DNO size. Our econometric models aim to test if the constant term in the regression is significant after considering the correlation between BSC and the size of the DNO. Statistically significant constants show evidence of fixed costs and separating the DSO from the DNO would require DSOs to duplicate these fixed costs. Since we are not interested in efficiency assessment of DNOs, inclusion of controllable variables in the models would not create concerns. Therefore, we consider variables that would be informative on the scale of a DNO, as shown in Table B.1.
### Table B.1: Candidate Drivers

<table>
<thead>
<tr>
<th>Candidate Drivers</th>
<th>Relevance as a scale variable and relevance with BSC</th>
</tr>
</thead>
</table>
| MEAV                      | • It reflects the scale and the composition of the network, but differences in composition of the network (e.g., overhead v underground) not directly relevant to BSCs  
                          | • Does not directly capture environmental factors (e.g., London or North of Scotland effects) causing differences in BSCs  
                          | • Data revisions during ED2 suggest the asset register is not entirely accurate                                            |
| Network Length            | • Alternative scale variables to MEAV, which may avoid some distortions associated with MEAV (e.g., OH vs UG)            |
| Customer numbers          | • Fail to capture complexity of network, but this may not be as relevant for BSCs                                        |
| Peak demand               | • Closely correlated with customer numbers. Shows positive relationship with the size of a DNO intuitively               |
| Units distributed         | • Closely correlated with customer numbers, indicative of the total demand of a company, the higher the total demand a company faces, the larger the DNO is likely to be, and the higher BSC it may incur |
| Load related costs        | • Indicative of how much a company spends on its load-related businesses, the higher the costs, the larger it is likely to be and the higher BSC it may incur  |
| Number of companies       | • Applicable to group level data, may capture the extent of fixed costs at the group level, depending on the model form    |

*Source: NERA analysis.*

### B.1.3. Model selection criteria

Following the selection of relevant cost driver, we have tested different econometric models and selected the econometric models based on the performance of those models against the following criteria:

- **Sign of the coefficients**: We exclude regression models that have estimated coefficients with signs that are not consistent with economic, technical, and commercial intuition.

- **Statistical significance**: We exclude consistently insignificant coefficients of candidate driver variables across a range of model specifications. The t-stat of a given coefficient is a measure of its statistical significance, i.e., how likely it is to be different from zero:
  - $|T\text{ stat}| > 1.96$: The coefficient is statistically significant at 5% level i.e., more than 95% confidence that it is not zero,
  - $1.645 < |T\text{ stat}| > 1.96$: The coefficient is statistically significant at 10% level, but not at 5% level i.e., 90-95% confidence that it is not zero,
  - $|T\text{ stat}| < 1.645$: The coefficient is not statistically significant i.e., too low confidence that it is not zero.

- **Explanatory power**: We select models with a high adjusted R-squared. The adjusted R squared measures how much variation in costs is explained by the model’s specification. The higher the value (in percentage terms), the higher the explanatory power.

- **Ofgem’s diagnostic tests**: We assess each model with regards to Ofgem’s four diagnostic tests used at ED1, to which we allocate varying importance (See Table B.2). All the tests
reported are considered passed if the p-value reported is above 0.05 or 0.10, depending on which significance level we choose (5% or 10%, respectively)

**Table B.2: Ofgem’s Diagnostic Tests at ED1**

<table>
<thead>
<tr>
<th>Diagnostic test</th>
<th>Purpose</th>
<th>Importance</th>
</tr>
</thead>
<tbody>
<tr>
<td>RESET test</td>
<td>Tests whether the model is misspecified (i.e., if the functional form of the model is correct)</td>
<td>High: Failure of this test could indicate that the model is misspecified, which risks statistically biased results</td>
</tr>
<tr>
<td>Chow test</td>
<td>Tests if parameter estimates are stable over time (i.e., tests if there is a structural break in the data)</td>
<td>Medium: it is incorrect to pool the data if coefficients are not stable over time. However, given that we are only using historical data in our analysis, it is less likely that there would be such a &quot;structural break&quot; in the data</td>
</tr>
<tr>
<td>White test</td>
<td>Tests if the error term is homoskedastic</td>
<td>Low: The lack of homoskedasticity can lead to bias in the standard errors of parameter estimates. However, this can be and is corrected by the use of clustered robust standard errors (which Ofgem used at ED1 and we have also used in our analysis)</td>
</tr>
<tr>
<td>Normality test</td>
<td>Tests if residuals are normally distributed</td>
<td>Low: The normality of residuals is not necessary for the parameter estimates to have good statistical properties</td>
</tr>
</tbody>
</table>

Source: NERA analysis.

**B.2. Most Econometric Models Show Statistically Significant Constant and Scale Coefficients**

**B.2.1. Regression model using MEAV as the scale driver**

We transform Ofgem’s ED1 approach into an econometric model with MEAV as the driver variable and a constant term, and as Table B.3 shows we find the constant term is statistically significant, suggesting that the Ofgem unit cost approach is not correct in not considering the fixed cost component.

\[
BSC = \alpha + \beta_1 \cdot MEAV + error
\]

**Table B.3: DNO Regression Results using MEAV and Licensee Level Data**

<table>
<thead>
<tr>
<th></th>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>13.8061</td>
<td>8.07</td>
<td>Reset</td>
<td>0.0000</td>
</tr>
<tr>
<td>MEAV</td>
<td>1.75e-06</td>
<td>12.07</td>
<td>Chow</td>
<td>0.3523</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.4859</td>
<td></td>
<td>White</td>
<td>0.0833</td>
</tr>
<tr>
<td>Normality</td>
<td></td>
<td></td>
<td></td>
<td>0.0200</td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test
At a group level, we also find the constant term is statistically significant (see Table B.4). However, the model only passes the White test and fails the rest three tests, indicating MEAV only may not be a good regression model to assess BSC at the group level.

### Table B.4: DNO Regression Results using MEAV and Group Level Data

<table>
<thead>
<tr>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>8.59324</td>
<td>2.07</td>
<td>Reset</td>
</tr>
<tr>
<td>MEAV</td>
<td>2.65e-06</td>
<td>18.02</td>
<td>Chow</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.8328</td>
<td></td>
<td>White</td>
</tr>
</tbody>
</table>

*Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test*

#### B.2.2. Regression models using NERA’s selection of potential cost drivers

In this section, we examine different model specifications using the cost drivers identified above. We only select and present the modelling results for regression models that have significant coefficient estimate for the selected cost drivers, pass the Reset test, and with a high adjusted R-squared.

##### B.2.2.1. Regression result using licensee level data

Table B.5 shows the results using load related costs (LRC) as the driver. We consider regressing business support cost on companies’ load related costs. We include a dummy variable “ED1” as the model fails the Chow test. The dummy variable equals to 1 in year 2016-2021 (i.e., ED1 period), and equals to 0 in year 2011-2015. The coefficient of the dummy variable measures the average difference of BSC in ED1 and DPCR5 period.

\[
BSC = \alpha + \beta_1 \times \text{load related costs} + \beta_2 \times \text{load related costs}^2 + \beta_3 \times ED1 + \text{error}
\]

### Table B.5: DNO Regression Results using LRC and Licensee Level Data

<table>
<thead>
<tr>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>21.7442</td>
<td>11.05</td>
<td>Reset</td>
</tr>
<tr>
<td>Load related costs</td>
<td>0.5219</td>
<td>5.67</td>
<td>Chow</td>
</tr>
<tr>
<td>Load related costs²</td>
<td>-4.0034</td>
<td>-3.58</td>
<td>White</td>
</tr>
<tr>
<td>ED1</td>
<td>2.8077</td>
<td>2.15</td>
<td>Normality</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.2476</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test*

Load related costs appears to be a poor scale driver for the BSC though the model predicts a significant and positive constant. The model only passes White test, and it still fails the Chow test after we include the ED1 dummy variable. The coefficient on load related costs and squared term of load related costs are both significant, with adjusted R-squared of 25 per cent.
Table B.6 shows the results using peak demand as the scale driver: The constant term and scale coefficients are statistically significant.

\[ BSC = \alpha + \beta_1 \times \text{peak demand} + \text{error} \]

**Table B.6: DNO Regression Results using Peak Demand and Licensee Level Data**

<table>
<thead>
<tr>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>17.5314</td>
<td>11.63</td>
<td>Reset</td>
</tr>
<tr>
<td>Peak demand</td>
<td>0.0041</td>
<td>11.31</td>
<td>Chow</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.4532</td>
<td></td>
<td>White</td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model passes Chow and White tests, with adjusted R-squared of 45 per cent. Both the constant and the coefficient are positive and significant, suggesting some BSC costs are fixed at the DNO level.

Table B.7 shows the regression result using customers number as the scale driver: Customers number appears to be a good driver for the BSC.

\[ BSC = \alpha + \beta_1 \times \text{customers number} + \text{error} \]

**Table B.7: DNO Regression Results using Customers Number and Licensee Level Data**

<table>
<thead>
<tr>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>16.8657</td>
<td>11.21</td>
<td>Reset</td>
</tr>
<tr>
<td>Customers number</td>
<td>7.89e-06</td>
<td>10.71</td>
<td>Chow</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.4489</td>
<td></td>
<td>White</td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model passes all but the Normality test, with adjusted R-squared of 45 per cent. Both the constant and the coefficient are positive and significant, suggesting exitance of DNO level fixed business support costs.

Table B.8 shows the result using units distributed as the scale driver: The constant term and scale coefficients are statistically significant.

\[ BSC = \alpha + \beta_1 \times \text{units distributed} + \text{error} \]
Table B.8: DNO Regression Results using Units Distributed and Licensee Level Data

<table>
<thead>
<tr>
<th></th>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>18.1707</td>
<td>10.44</td>
<td>Reset</td>
<td>0.0205</td>
</tr>
<tr>
<td>Units distributed</td>
<td>0.0008</td>
<td>11.60</td>
<td>Chow</td>
<td>0.7867</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.4176</td>
<td></td>
<td>White</td>
<td>0.3716</td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test.

The model passes the Chow and White test, with adjusted R-squared of 42 per cent. Both the constant and the coefficient are positive and significant, suggesting exitance of DNO level fixed business support costs.

Table B.9 shows the regression result using network length as the scale driver: The constant term and scale coefficients are statistically significant.

\[ BSC = \alpha + \beta_1 \times \text{network length} + \text{error} \]

Table B.9: DNO Regression Results using Network Length and Licensee Level Data

<table>
<thead>
<tr>
<th></th>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>14.4897</td>
<td>7.48</td>
<td>Reset</td>
<td>0.2206</td>
</tr>
<tr>
<td>Network length</td>
<td>0.0003</td>
<td>10.25</td>
<td>Chow</td>
<td>0.7670</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.4046</td>
<td></td>
<td>White</td>
<td>0.5022</td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test.

The model passes all but Normality test, with adjusted R-squared of 40 per cent. Both the constant and the coefficient are positive and significant, suggesting exitance of DNO level fixed business support costs.

Table B.10 shows the regression result using a combination of network length and peak demand as driver variables: The constant term and scale coefficients are statistically significant.

\[ BSC = \alpha + \beta_1 \times \text{network length} + \beta_2 \times \text{peak demand} + \text{error} \]
Table B.10: DNO Regression Results using Network Length, Peak Demand and Licensee Level Data

<table>
<thead>
<tr>
<th></th>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>13.8830</td>
<td>7.73</td>
<td>Reset</td>
<td>0.0000</td>
</tr>
<tr>
<td>Network length</td>
<td>0.0002</td>
<td>3.47</td>
<td>Chow</td>
<td>0.8216</td>
</tr>
<tr>
<td>Peak demand</td>
<td>0.0027</td>
<td>5.15</td>
<td>White</td>
<td>0.0076</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.4902</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model passes only the Chow test, with adjusted R-squared of 49 per cent. Both the constant and the coefficient are positive and significant, suggesting exitance of DNO level fixed business support costs.

Table B.11 shows the result using network length and customers number as scale drivers: The constant term and scale coefficients are statistically significant.

\[ BSC = \alpha + \beta_1 \times \text{network length} + \beta_2 \times \text{customers number} + \text{error} \]

Table B.11: DNO Regression Results using Network Length, Customers Number and Licensee Level Data

<table>
<thead>
<tr>
<th></th>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>14.2446</td>
<td>7.80</td>
<td>Reset</td>
<td>0.0000</td>
</tr>
<tr>
<td>Network length</td>
<td>0.0001</td>
<td>2.69</td>
<td>Chow</td>
<td>0.4002</td>
</tr>
<tr>
<td>Customer numbers</td>
<td>5.30e-06</td>
<td>4.47</td>
<td>White</td>
<td>0.2008</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.4706</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model passes the Chow and White test, with adjusted R-squared of 47 per cent. Both the constant and the coefficient are positive and significant, suggesting some business support costs are fixed at DNO level.

Table B.12 shows the regression result using customers number and load related costs as scale drivers: The constant term and scale coefficients are statistically significant.

\[ BSC = \alpha + \beta_1 \times \text{customers number} + \beta_2 \times \text{load related costs} + \text{error} \]
Table B.12: DNO Regression Results using Customers Number, Load Related Costs and Licensee Level Data

<table>
<thead>
<tr>
<th></th>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>16.7026</td>
<td>10.76</td>
<td>Reset</td>
<td>0.0656</td>
</tr>
<tr>
<td>Load related costs</td>
<td>0.0713</td>
<td>2.42</td>
<td>Chow</td>
<td>0.9262</td>
</tr>
<tr>
<td>Customer numbers</td>
<td>7.07e-06</td>
<td>9.15</td>
<td>White</td>
<td>0.2113</td>
</tr>
<tr>
<td>Adjusted (R^2)</td>
<td>0.4659</td>
<td></td>
<td>Normality</td>
<td>0.0114</td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model passes all but the Normality test, with adjusted R-squared of 47 per cent. Both the constant and the coefficient are positive and significant, suggesting some business support costs are fixed at DNO level.

B.2.2.2. Regression result using group level data

Table B.13 shows the results using load related costs as the driver: We consider regressing business support cost on companies’ load related costs. We include a dummy variable “ED1” as the model fails Chow test. The dummy variable equals to 1 in year 2016-2021 (i.e., ED1 period), and equals to 0 in year 2011-2015. The coefficient of the dummy variable measures the average difference of BSC in ED1 and DPCR5 period.

\[
BSC = \alpha + \beta_1 \cdot load \text{ related costs} + \beta_2 \cdot load \text{ related costs}^2 + \beta_3 \cdot ED1 + error
\]

Table B.13: DNO Regression Results using LRC and Group Level Data

<table>
<thead>
<tr>
<th></th>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>16.0332</td>
<td>2.87</td>
<td>Reset</td>
<td>0.1535</td>
</tr>
<tr>
<td>Load related costs</td>
<td>1.0576</td>
<td>9.69</td>
<td>Chow</td>
<td>0.2949</td>
</tr>
<tr>
<td>Load related costs(^2)</td>
<td>-0.0023</td>
<td>-4.95</td>
<td>White</td>
<td>0.0226</td>
</tr>
<tr>
<td>ED1</td>
<td>18.9305</td>
<td>4.91</td>
<td>Normality</td>
<td>0.0467</td>
</tr>
<tr>
<td>Adjusted (R^2)</td>
<td>0.7611</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model passes the Reset test. We add the dummy variable for ED1 period to address the problem of structural break. The coefficient on load related costs and squared term of load related costs are both significant, with adjusted R-squared of 76 per cent. The model predicts a positive and significant constant, suggesting group level fixed costs exist.

Table B.14 shows the result using peak demand as the scale driver: Peak demand appears to be a good driver for BSC at group level.

\[
BSC = \alpha + \beta_1 \cdot peak \text{ demand} + error
\]
Table B.14: DNO Regression Results using Peak Demand and Group Level Data

<table>
<thead>
<tr>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>18.3956</td>
<td>5.16</td>
<td>0.1207</td>
</tr>
<tr>
<td>Peak demand</td>
<td>0.0067</td>
<td>18.44</td>
<td>0.0413</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.8392</td>
<td></td>
<td>0.4268</td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model passes all but the Chow test, with adjusted R-squared of 84 per cent. Both the constant and the coefficient are positive and significant, suggesting some BSC costs are fixed at the group level.

Table B.15 shows the regression result using peak demand and network length as the scale driver: The combination of driver variables estimates statistically significant constant and coefficient terms.

\[
BSC = \alpha + \beta_1 \times \text{peak demand} + \beta_2 \times \text{network length} + \text{error}
\]

Table B.15: DNO Regression Results using Peak Demand, Network Length and Group Level Data

<table>
<thead>
<tr>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>14.9566</td>
<td>4.27</td>
<td>0.0861</td>
</tr>
<tr>
<td>Peak demand</td>
<td>0.0034</td>
<td>3.21</td>
<td>0.0041</td>
</tr>
<tr>
<td>Network length</td>
<td>0.0002</td>
<td>3.18</td>
<td>0.0075</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.8593</td>
<td></td>
<td>0.0828</td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model passes all but the Chow test, with adjusted R-squared of 86 per cent. Both the constant and the coefficient are positive and significant, suggesting some BSC costs are fixed at the group level.

Table B.16 shows results regressing BSC on network length and units distributed: The constant term and scale coefficients are statistically significant.
\[ BSC = \alpha + \beta_1 \times \text{network length} + \beta_2 \times \text{units distributed} + \text{error} \]

Table B.16: DNO Regression Results using Network Length, Units Distributed and Group Level Data

<table>
<thead>
<tr>
<th></th>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>13.1649</td>
<td>4.24</td>
<td>Reset</td>
<td>0.1283</td>
</tr>
<tr>
<td>Network length</td>
<td>0.0003</td>
<td>3.79</td>
<td>Chow</td>
<td>0.0041</td>
</tr>
<tr>
<td>Units distributed</td>
<td>0.0005</td>
<td>2.67</td>
<td>White</td>
<td>0.0066</td>
</tr>
<tr>
<td>Adjusted R(^2)</td>
<td>0.8529</td>
<td></td>
<td>Normality</td>
<td>0.0413</td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model only passes the Reset tests with adjusted R-squared of 85 per cent. Both the constant and the coefficient are positive and significant, suggesting some BSC costs are fixed at the group level.

Table B.17 shows result on regressing BSC on load related costs and customer numbers: The constant term and scale coefficients are statistically significant.

\[ BSC = \alpha + \beta_1 \times \text{load related costs} + \beta_2 \times \text{customers number} + \text{error} \]

Table B.17: DNO Regression Results using Load Related Costs, Customers Number and Group Level Data

<table>
<thead>
<tr>
<th></th>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>20.9621</td>
<td>6.27</td>
<td>Reset</td>
<td>0.5244</td>
</tr>
<tr>
<td>Load related costs</td>
<td>0.1824</td>
<td>4.51</td>
<td>Chow</td>
<td>0.0042</td>
</tr>
<tr>
<td>Customer numbers</td>
<td>9.32e-06</td>
<td>10.97</td>
<td>White</td>
<td>0.0012</td>
</tr>
<tr>
<td>Adjusted R(^2)</td>
<td>0.8601</td>
<td></td>
<td>Normality</td>
<td>0.2804</td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant. Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model only passes the Chow and White tests with adjusted R-squared of 86 per cent. Both the constant and the coefficient are positive and significant, suggesting some BSC costs are fixed at the group level.

Table B.18 shows the result regressing BSC on network length and load related costs: The constant term and scale coefficients are statistically significant.

\[ BSC = \alpha + \beta_1 \times \text{network length} + \beta_2 \times \text{load related costs} + \text{error} \]
Table B.18: DNO Regression Results using Network Length, Load Related Costs and Group Level Data

<table>
<thead>
<tr>
<th></th>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>17.3137</td>
<td>5.06</td>
<td>Reset</td>
<td>0.0595</td>
</tr>
<tr>
<td>Network length</td>
<td>0.0004</td>
<td>11.60</td>
<td>Chow</td>
<td>0.1567</td>
</tr>
<tr>
<td>Load related costs</td>
<td>0.1617</td>
<td>4.06</td>
<td>White</td>
<td>0.0008</td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.8702</td>
<td></td>
<td>Normality</td>
<td>0.3626</td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant, Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model passes all tests but the White test, with adjusted R-squared of 87 per cent. Both the constant and the coefficient are positive and significant, suggesting some BSC costs are fixed at the group level.

Table B.19 shows the result regressing BSC on peak demand, load related costs and number of companies with ED1 dummy variable: The model also performs well on statistical standpoint.

\[
BSC = \alpha + \beta_1 \times \text{peak demand} + \beta_2 \times \text{load related costs} + \beta_3 \times \text{number of companies} + \beta_4 \times ED1 + \text{error}
\]

Table B.19: DNO Regression Results using Peak Demand, Load Related Costs, Number of Companies and Group Level Data

<table>
<thead>
<tr>
<th></th>
<th>Coefficients</th>
<th>T-stats</th>
<th>Diagnostic Test</th>
<th>P-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>13.1649</td>
<td>3.63</td>
<td>Reset</td>
<td>0.7861</td>
</tr>
<tr>
<td>Peak demand</td>
<td>0.0032</td>
<td>4.10</td>
<td>Chow</td>
<td>0.1202</td>
</tr>
<tr>
<td>Load related costs</td>
<td>0.1752</td>
<td>3.80</td>
<td>White</td>
<td>0.0694</td>
</tr>
<tr>
<td>Number of companies</td>
<td>9.1281</td>
<td>2.85</td>
<td>Normality</td>
<td>0.6416</td>
</tr>
<tr>
<td>ED1</td>
<td>18.9305</td>
<td>2.16</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Adjusted R²</td>
<td>0.8821</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: Coefficient significant at 5% level, Significant at 10% level, Not Significant, Model passes test at 5% level, Model passes test at 10% level, Model fails test

The model passes all tests with adjusted R-squared of 88 per cent. Both the constant and the coefficient are positive and significant, suggesting some BSC costs are fixed at the group level.

B.2.3. Evidence of fixed component in BSC suggests there will be duplication of overheads on separation

All the above regressions show statistically significant constant terms, supporting our hypothesis that there are fixed costs (either at the group or licensee level) that would need to be duplicated if DNOs and DSOs were separated. Table B.20: and Table B.21: also summarise our estimate of the degree to which total business support costs are fixed, which we estimate by taking the values of the constant terms in each linear regression model.
Table B.20: shows that across a range of alternative model specifications estimated at the licensee level, our estimate of the degree of fixed costs ranges from £13.8 million to £21.7 million (2020/21 prices) per DNO licensee. Since the average annual business support costs of 14 DNOs from 2011-2021 is £33.6 million (2020/21 prices), our analysis suggests that between 41 per cent 65 per cent of the business support costs are fixed costs that are invariant to the scale of a DNO and could therefore need to be duplicated by both DNO and DSO upon separation.

Table B.21: provides a similar set of results from regressions estimated at the DNO group level, and suggests fixed costs between £13.2 million and £21.0 million per DNO group (2020/21 prices). Since the average annual business support costs of 6 DNO groups from 2011-2021 is £78.3 million (2020/21 prices), that means that between 19 per cent and 27 per cent of the average DNO group’s business support costs are fixed costs that are invariant to the scale of a DNO and could therefore need to be duplicated by both DNO and DSO upon separation.

### Table B.20: Summary of Regression Results on Licensee Level Data

<table>
<thead>
<tr>
<th>Drivers</th>
<th>Estimation of annual fixed BSC per Licensee (2020/21 £m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MEAV</td>
<td>13.8</td>
</tr>
<tr>
<td>Load related cost + load related cost^2 + ED1</td>
<td>21.7</td>
</tr>
<tr>
<td>Peak demand</td>
<td>17.5</td>
</tr>
<tr>
<td>Customers number</td>
<td>16.9</td>
</tr>
<tr>
<td>Units distributed</td>
<td>18.2</td>
</tr>
<tr>
<td>Network length</td>
<td>14.5</td>
</tr>
<tr>
<td>Network length + Peak demand</td>
<td>13.9</td>
</tr>
<tr>
<td>Network length + customers number</td>
<td>14.2</td>
</tr>
<tr>
<td>Customers number + load related costs</td>
<td>16.7</td>
</tr>
</tbody>
</table>

*Source: NERA analysis on DNO data.*

### Table B.21: Summary of Regression Results on DNO Group Data

<table>
<thead>
<tr>
<th>Model specification</th>
<th>Estimation of fixed costs per DNO group (2020/21 £m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BSC – load related costs + load related costs^2 + ED1</td>
<td>16.0</td>
</tr>
<tr>
<td>BSC – peak demand</td>
<td>18.4</td>
</tr>
<tr>
<td>BSC – peak demand + network length</td>
<td>15.0</td>
</tr>
<tr>
<td>BSC – network length + units distributed</td>
<td>13.2</td>
</tr>
<tr>
<td>BSC – load related costs + customer numbers</td>
<td>21.0</td>
</tr>
<tr>
<td>BSC – network length + load related costs</td>
<td>17.3</td>
</tr>
<tr>
<td>BSC – peak demand + load related costs + number of companies + ED1</td>
<td>18.9</td>
</tr>
</tbody>
</table>

*Source: NERA analysis on DNO data.*
Appendix C. The Implications of Introducing Distribution Locational Marginal Pricing (LMP)

C.1. LMP at Distribution Voltages

We understand from SSE that Ofgem is considering the introduction of Locational Marginal Pricing (LMP) of energy in the British wholesale market, which could – at least in principle – be applied to both transmission and distribution systems. This section is not intended to assess the merits of introducing LMP or assess how the practical difficulties of implementing trade-off against the potential efficiency benefits. Such an assessment would require the development and design of new market arrangements, and an impact assessment of those new arrangements by Ofgem. Below we comment solely on whether our recommendations in respect of DSO governance are affected by Ofgem’s possible consideration of LMP.

Under an LMP model, wholesale prices would (as now) be determined by the interaction of supply and demand in the market, but with LMP different “nodes” within the transmission and distribution networks would each have their own wholesale price, with differences between nodal prices possible due to congestion between nodes and/or losses between nodes. Extending LMP into the lower distribution voltages is theoretically appealing in its potential to promote efficient despatch and send efficient locational and time-of-use signals for energy usage.

In theory, it would price in congestion and losses on the distribution network into wholesale price differentials across locations. This may be useful for improving the efficiency of economic signals regarding the value of DERs, including generation, Demand Side Management (DMS), and storage. It could also provide improved signals regarding the value of distribution network investments to relieve congestion between parts of the network, i.e., allowing an improvement in the planning process that accounts for the economic value of distribution network capacity beyond the need to meet pre-determined planning standards. LMP at distribution voltages could also provide a mechanism for the efficient dispatch of DERs, and potentially substitute for the existing role played by DNOs in curtailing DERs’ access to the network when it is constrained.

However, while using LMP within a distribution system has theoretical appeal and despite its track record of use by North American Independent System Operators (ISOs) at transmission levels, extending LMP into the lower voltages of distribution utilities is (to our knowledge) unprecedented internationally. Implementing LMP in distribution systems would raise several practical challenges, most notably the need for the central despatcher / market operator to have a high degree of information about real time network conditions that may not be available for the DNOs’ networks (especially the lower voltages).

There would be other practical difficulties and costs associated with introducing LMP, and further costs associated with extending it to distribution voltages, including the substantial transactions and administrative costs it entails such as re-writing existing market rules, industry agreements and contracts for power exchange and network access, and establishing new market systems and regulatory processes (e.g., governing network expansion planning).

Assessing the advantages and disadvantages of LMP (either at the transmission or distribution level) is substantially beyond the scope of this report. However, we have ...
considered whether our recommendation, that there is currently no case for the degree of separation between DSO and DNO to go beyond ringfencing, would change due to the possibility of Ofgem introducing LMP for distribution systems.

**C.2. Strawman of a Possible Model for Organising Distribution LMP**

To inform this assessment, below we set out a strawman model of how the role of the DNO/DSO could change following the introduction of LMP at distribution voltages. However, we note this characterisation of how the DNO/DSO role would change is only one possible model, and significant further work on industry governance would be needed if this LMP model were implemented.

If a single, unified system of LMP were introduced across the whole of GB, it is likely that this single system would need to be administered centrally. Hence, we assume the ESO would take responsibility for running a market clearing algorithm that determines dispatch patterns across the whole of GB and sets nodal prices for each trading interval. To the extent this system of LMP covers distribution systems, this dispatch algorithm would also determine the prices and dispatch patterns of DERs located within distribution systems. It would also take responsibility away from the DNO/DSOs for managing congestion in real time in the parts of the network it covers.

However, it is possible (and indeed likely) that parts of the distribution network at lower voltages would not be covered by LMP, e.g., where not enough information is known about real time network conditions to enable it to be included in the market clearing algorithm. In these parts of the network, the DSO would need to continue to manage any congestion, and either curtail load or dispatch flexibility resources to manage congestion that has not already alleviated through network investment. DERs located within these parts of the distribution systems not covered by LMP could still offer into the national wholesale market (to the extent that their network access allows), just as they do now from the perspective of the DNO/DSO. However, they would face a nodal price at the transmission-distribution interface, instead of a national one when they do so.

Hence, there would (in effect) be two dispatching functions within distribution systems:

- DERs in parts of the network covered by LMP would be dispatched centrally, most likely by the ESO. DERs located in other parts of the network could also be dispatched in this way, i.e., against the nodal price at the relevant transmission-distribution interface; or
- Alternatively, DERs could also be dispatched by the DNO/DSO where they have flexibility contracts (as now).

Hence, if a central system of LMP were extended into the distribution voltages, the role played by the DSO in despatching DERs to manage congestion would be removed in those parts of the network covered by LMP. However, the DNO/DSO would still have a number of important roles to play in planning the network, even if real time congestion management were conducted by the ESO:

- The **DNO/DSO would still be responsible for maintenance, repair, and fault restoration on its network assets.** This means that it would continue to make operational decisions about the stewardship of the network in real time, though there may need to be a new process for notifying the ESO of reductions in capacity on distribution lines when faults...
or maintenance outages occur, so these could (at least in principle) be factored into the nodal despatch algorithm. This would require new industry processes at the DSO-ESO interface (or comparable internal processes within an amalgamated ESO-DSO, if that option were pursued). Nonetheless, LMP would have little impact on the numerous investment decisions needed within distribution systems on a day-to-day basis to resolve faults (i.e., repair, replace or expand). Because there are trade-offs between the day-to-day investment decisions that must be taken by the DNO and decisions to expand network capacity that could be taken by an independent DSO, our conclusion in the main report remains unchanged, i.e., that the costs of DSO separation are likely to be significant due to the large number of required interactions between the DSO and DNO.

- **The DNO/DSO would still need to undertake planning decisions.** In an LMP model, sections of the DNO’s network covered by LMP may need to be governed by new planning processes and standards, reflecting the fact that: (1) LMP enables more information to be revealed on trade-offs between congestion and infrastructure costs so current planning practices may need to evolve; and (2) investments that relieve transmission and distribution constraints have greater commercial implications for individual investors (because they narrow locational price differentials) than at present. However, there would still be a centralised process – led by a regulated monopolist (DSO/ESO/DNO) – regarding whether to develop new network reinforcements:
  - In sections of the distribution network not covered by LMP, there would be no material change compared to the current situation. DNOs would still face trade-offs between flexibility contracts and other network solutions when investing to meet their security standards. Hence, the conclusions made in our report would be unaffected regarding the small benefits from separation stemming from avoiding the actual or perceived conflicts of interest, relative to the likely costs of separation.
  - In parts of the network covered by LMP:
    - The DNO/DSO’s planning processes may change with the introduction of LMP but will still involve a trade-off between congestion costs and measures taken by the network operator to relieve that congestion and choosing between network reinforcements and contracts with third parties. One particular change relates to the specification of flexibility contracts, which would have to be re-written to accommodate the fact that DERs would all be dispatched centrally and would receive or pay the nodal price when they are dispatched. Hence, the flexibility contract with the DNO could (if they are the appointed counterparties) become a financial hedging arrangement that guaranteed the flexibility provider a stable revenue and the DNO predictable costs. However, as long as the costs incurred by the DNO under these contracts are covered by the TIM, there is no particular change in the case for business separation as compared to the findings in our report, because an integrated DSO/DNO would have incentives to choose between these options in a way that minimises totex. As such, the use of LMP to dispatch flexibility resources would not improve the economic case for separating the DSO from the DNO.
    - The role of the DSO would become slightly narrower because it would no longer be responsible for real time dispatch of flexibility resources. This reduction in the
scope of the DSO would avoid any perception of conflicts of interest it might have in the dispatching activity, and therefore reduce the case for separation from the DNO.

C.3. **Implications for DSO Governance Options from Distribution LMP**

Because LMP at distribution voltages is unprecedented and would be challenging to implement, it is premature to alter governance arrangements in anticipation of such a substantial – and at this stage speculative – change in market design.

For example, because applying LMPs in the distribution system is unprecedented, we cannot know precisely how the DNO/DSO governance arrangements would need to change at this point. Therefore, the possibility that LMP may be extended into distribution systems and the uncertainty around how it would affect governance arrangements if it did happen, means a substantive change to DNO/DSO arrangements in response to an expectation of Ofgem implementing a distribution LMP market would be highly premature and risk incurring wasteful costs if this does not take place. This supports our recommendation to implement relatively low-cost ringfencing in the near-term, rather than the more costly legal separation.

Moreover, depending on how LMP is introduced at lower voltage levels, our recommended approach of ringfencing without full legal separation could remain an appropriate approach to governing the DNO/DSO interface (as set out above). The possibility that ringfencing provides sufficient separation between the DNO and DSO, even if LMP were extended to the distribution system, means making more significant changes to governance now in anticipation of an LMP market design would be premature and risks incurring wasteful expenditure.
Appendix D. Bibliography


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