

RIIO-2 Challenge Group Response to Draft Determinations

August 2022

Electricity Distribution

Contents

Executive Summary.....	3
1. Embedding the consumer voice in ED2	5
2. Outputs and incentives.....	6
3. Networks for Net Zero – load-related expenditure	15
4. A smarter, more flexible, digitally-enabled energy system.....	30
5. Delivering at lowest cost to energy consumers	43
6. Uncertainty mechanisms	56
7. Finance	58

Executive Summary

The RIIO-2 Challenge Group is pleased to respond to the Ofgem ED2 Draft Determination. We have highlighted our main comments below.

Flexibility first

A step change is needed to optimise existing DNO network utilisation and to free up capacity. It is also vital to enable distributed energy resources to participate in both local and national flexibility and energy markets. This could deliver huge benefits by reducing the need for additional network and generation capacity. DSO flexibility offers an important route to seeding this market. It is critical that the DSOs are incentivised to deliver outcomes that are both valuable to customers and are measurable. DSO incentives should be targeted on outcomes such as improved utilisation of networks in congested areas, and volumes of traded flexibility resources.

Load-related expenditure and uncertainty mechanisms

We welcome the use of higher baseline allowances and uncertainty mechanisms to fund load-related expenditure. In our view, this strikes the right balance between delivering Net Zero and protecting consumers from unnecessary costs. It should enable the proactive approach to load-related investment needed for Net Zero.

The key risk is that investment delays constrain the move to Net Zero. For that reason the proposed ED2 mid-point review should address the need for further anticipatory investment, based on the best available independent forecasts. But it is of course possible that those forecasts of future demand are reduced, as a result, for example, of better network utilisation or changes in long term demand patterns, so the uncertainty mechanisms should be symmetrical, to allow for this possibility.

Totex

Ofgem is proposing to allow a level of non-load-related expenditure that is 7% more than in ED1 – even after allowing for efficiency improvements. It is not clear why there should be any increase at all or why some companies have higher increases than others. Savings of up to £1.2 billion could be realised for customers by keeping these costs at current levels.

Whole system

There are very different levels of ambition among the DNOs and, most importantly, there are few performance measures and output targets arising from these activities. There is a risk that DNOs take a reactive approach to whole-system initiatives, with ineffective engagement with ESO, local authorities and other stakeholders. As such, Ofgem's proposal to fund all DNO whole system plans as baseline without such measurement means that it will be difficult to identify strong and weak performance and to encourage improvement. We would suggest that appropriate measures of performance and incentives are established, perhaps combined with DSO incentives, and focusing on whole-system outcomes wherever possible.

Outputs and incentives

We agree with Ofgem's asymmetric approach in regard to over- and under-performance. But we are concerned that there are significant differences between companies in their performance and funding proposals for some important outputs - including support for consumers in vulnerable circumstances and reliability. Ofgem's approach to incentives and target-setting in these areas does not seem to

narrow the gap between DNOs meaningfully over time. This could leave customers in some areas receiving materially worse standards of service for the long term. It is also important that incentives for DSO and flexibility work alongside the sharing factor for totex savings. Customers should not have to pay for assets that would not be needed if full use were made of the potential for flexibility.

Finance

We accept that the asymmetry in some incentive mechanisms increases risk to some extent, but that is more than offset by the increased use of uncertainty mechanisms. The history of DNO outperformance and the prospect of large windfall gains arising from the unexpected leap in inflation mean that the likelihood of upside remains much higher than the downside risk, and that the proposed rate of return on equity is unduly generous.

1. Embedding the consumer voice in ED2

The ED2 Draft Determinations overview document provides a high-level overview of the key proposals from the Draft Determination to achieve Net Zero at least cost. It summarises the Ofgem proposals for:

- Key outputs and incentives for ED2
- Ensuring an efficient cost of service to customers, including uncertainty mechanisms and efficient financing
- Optimisation of existing network capabilities to support the Net Zero transition.

We have addressed the DD consultation questions in the subsequent chapters of our response.

Embedding the consumer voice in ED2

The RIIO-ED2 Challenge Group (CG) is independently chaired and comprised of energy sector experts and consumer advocates with specialist knowledge of the electricity distribution sector and economic regulation.

In line with our primary objectives, the CG provides an independent challenge to, and scrutiny of, draft and final ED2 Business Plans from the perspective of current and future consumers. The group focussed on affordability, the protection of consumers in vulnerable circumstances, and sustainability - including but not limited to the impact on the environment and the net-zero transition.

We provided Ofgem with a report in February 2022¹ setting out our views on each DNO's final Business Plan. This was published on the Ofgem website. We also contributed to the Open Hearings held earlier this year.

We have addressed the following Ofgem question in our response below:

Core-Q1. Do you agree with our proposals for the enduring role of the CEG?

Ofgem believes that the 'enhanced engagement' process it has required DNOs to adopt for its ED2 business plans has worked well. This includes each DNO having to establish a Customer Engagement Group (CEG) to provide independent scrutiny and challenge to its plans.

In the DD, it says that it 'welcomes indications' from the DNOs that they are planning to continue to use their independent CEGs, or 'groups with similar independence, remit and expertise' to challenge the implementation of their plans, and their delivery of their commitments. As a result, Ofgem says that it does not see the need to place a formal requirement on DNOs to keep such groups.

This is the same position that Ofgem took with the other network sectors which are two years ahead of DNOs in their RIIO-2 price control period. However, we believe that, although these other network companies may all have independent groups in place, they are not being used in a consistent or equally rigorous way. Ofgem should, therefore, anticipate a similar range of approaches from the DNOs. If it believes that this is a valuable way to enhance the voice of consumers and stakeholders in the delivery of BP commitments, it should at least set out minimum expectations for these groups and how it plans to hold DNOs to account for their use.

¹ RIIO-2 Challenge Group Independent Report to Ofgem on Electricity Distribution Business Plans | Ofgem

2. Outputs and incentives

In this chapter, we have addressed the outputs and incentives included in Ofgem's Core document chapters, including:

- Chapter 3. Meeting the needs of customers and network users
- Chapter 4. Maintaining a safe, resilient, and reliable network

Overview of outputs and incentives

The DD now sets out a revised overall value for the ED2 common output incentive package. The value of several outputs in ED1 was based on a percentage of each DNO's base revenue. But, for ED2, Ofgem has based the value of all outputs on a percentage of each company's Rate of Regulatory Equity (RoRE). The DD shows how the value of base revenue translates to RoRE and we have used these figures to compare output values on a like-for-like basis (shown in Table 1, below).

Table 1: Value of outputs in ED2 compared with ED1

	ED1 (value as % of RoRE)	ED2 (value as % of RoRE)
Customer satisfaction	+0.4/- 0.4%	+0.4%/- 0.4%
Complaints	+0/-0.2%	+0/-0.2%
Time to connect	+0.15%/- 0.15%	+0.15%/- 0.15%
Incentive on connections engagement/ Major connections	+0/-0.35%	+0/-0.35%
Stakeholder engagement and customer vulnerability/ Vulnerability strategy delivery	+0.2%/-0.2%	+0.2%/-0.2%
DSO strategy delivery		+0.2%/-0.2%
Interruptions incentive scheme	+2.5/-2.5%	+1%/-2.5%
Total	+3.25%/-3.8%	+1.95%/-4%

Challenge group comments

The maximum rewards available to DNOs for their performance on these various output measures is now 1.3% of RoRE less than it was during ED1. However, the maximum potential penalty is similar at -4% compared with -3.8% in ED1. The shift is due to Ofgem's newly proposed 1.5% reduction in the maximum value of the reliability incentive, the Interruptions Incentive Scheme (IIS), partly offset by the new DSO incentive worth up to 0.2% of RoRE.

We support this shift to an asymmetric package – where the maximum penalties are greater than the maximum rewards. This reflects the fact that DNOs' performance in many areas improved significantly during ED1. For ED2, it is important that these standards now become business as usual and that there are tough penalties in place to avoid them deteriorating. It is also appropriate for DNOs to have to work harder to earn additional rewards in ED2.

However, we would highlight the following points:

- On the IIS: Ofgem says in its DD that it is not the reduction in the incentive reward cap that will constrain payments to DNOs in this area. Instead, it says that it is the fact that not all DNOs can continue to deliver further reliability improvements on their networks at the same level of costs allowed in ED1. It has rejected DNOs' arguments to increase these 'incentive rates' and says that it wants to see strong evidence that consumers are prepared to pay significantly higher prices for further reliability improvements before it will consider this (see 'Maintain a safe secure and resilient network', p11, for more on this). As a result, Ofgem appears to be saying that this cap is simply a better reflection of the upside value of its original reliability proposals rather than representing a significant change to them.
- On vulnerability: we recognise that, in ED1, this incentive was rewarding DNO performance in two areas – stakeholder engagement and support for customers in vulnerable circumstances. Ofgem now expects DNOs to undertake high quality stakeholder engagement as a matter of course and will no longer incentivise them financially to improve in this area. However, the value of this incentive has stayed the same in ED2 – effectively increasing the financial incentive for DNOs to deliver their new vulnerability strategies. We welcome this greater emphasis in this important area.
- On DSO: this is a new output incentive for ED2 and is valued at +/-0.2% of RoRE – in line with Ofgem's other 'strategy delivery incentives' in the areas of connections and vulnerability. We welcome the focus on this critical area. However, as with other strategy areas, we are concerned about variability created by accepting DNOs' very different strategies. We are also concerned that the incentive will not be strong enough to drive the fundamental change in behaviour that is required to ensure DNOs put 'flexibility first' (see Chapter 4 'A smarter, more flexible and digitally-enabled energy system', for more on this).

Approach to DNOs' bespoke strategies

Ofgem has largely accepted DNOs' strategies in the areas of vulnerability, DSO and major connections in their entirety, having satisfied itself that they meet its baseline expectations. However, there is considerable variability between the strategies which will mean consumers and stakeholders in different areas are likely to receive quite different standards or benefits. Ofgem is working with the DNOs to establish common metrics to measure their performance in these areas. But, while the metrics will be consistent, the targets are often bespoke, and it wasn't clear to us how this approach would narrow the variability in performance over time.

Regional differences in population profiles, or materially different levels of stakeholder support for specific initiatives in different regions may be legitimate reason for different standards. But it wasn't clear from the DD that Ofgem had scrutinised the strategies in sufficient detail to satisfy itself that this was always the case. However, we do not think that it is acceptable that standards should be different because DNOs are 'starting from different positions'. In most areas, they have been subject to the same regulatory regime for many years and it is not clear why such differences have persisted. In newer areas, the best performers may have started to define best practice and we think Ofgem should be able to use its scrutiny of the DNOs' strategies to identify best practice in key areas, and then seek to apply those standards more widely.

CVPs

We have addressed the following Ofgem question in our response below:

Q8. Do you agree with our overall approach regarding the treatment of CVP proposals?

Ofgem's assessment of the various CVP proposals (20 proposals with possible reward value of £800m) is broadly in line with the views we set out in our Report. The three proposals accepted as justifying a reward are all ones we had recognised as having some merit. We agree with Ofgem on the need for safeguards around delivery where a reward is proposed.

We note that Ofgem has accepted a number of CVP proposals for baseline funding without a reward. Where activities were assessed as being part of 'business as usual' for a DNO, and outputs had support from CEGs and customers (on the basis of effective consultation) this generally seems a sensible approach.

We agree with the assessment that DNOs are not necessarily best placed to deliver some of the proposed customer-facing activity including the installation of smart meters. In particular, we agree that the ENWL Smart Street proposal should not receive a CVP. We continue to have reservations about Smart Street and particularly the scale of the baseline funding proposed. We have provided further comments in the section on 'Bespoke outputs and PCDs', below.

The proposed result of the CVP assessment is three modest rewards for specific initiatives in the SSE and WPD business plans. We are concerned that this is not a meaningful indicator of the overall quality of the BPs, although the CVP assessment is intended to be the key indicator of quality within the business planning process.

We acknowledge that the possibility of a CVP reward has encouraged some innovative thinking during the business planning process, has led to the inclusion of initiatives which should deliver benefits for customers and consumers and may have encouraged ambition, although we consider that ambition has been promoted more effectively through enhanced engagement. We also recognise that it would not be straightforward to construct a robust means for assessing quality and ambition across all, or multiple facets of, DNO business plans.

Nevertheless, we would encourage Ofgem to revisit the design of the qualitative dimension of the BP incentive before the next round of price controls.

Support for consumers in vulnerable situations

We have addressed the following Ofgem questions in our response below:

Core Q32. Do you agree with our proposal to remove the activities proposed from DNOs' baseline allowances?

Core Q33. Do you agree with our proposals for the Consumer Vulnerability ODI-F?

Core Q34. Do you agree with the performance metrics we are proposing to include in the incentive and the approach to setting targets and associated dead bands, performance caps and penalty collars? If not, please explain why and give details of your preferred alternative.

We support many of the proposals that Ofgem has set out in its DD in relation to DNOs' plans to support customers in vulnerable situations. However, we would challenge Ofgem to go further in some areas. In

particular, we are concerned about the wide variability of support that consumers in different network areas are likely to continue to receive during the ED2 period - and potentially beyond.

For the vulnerability incentive, Ofgem has decided to shift to an automatic mechanism to decide the value of rewards or penalties in this area. We support this as it should mean that DNOs' performance in this important area will be measured in an objective, comparable way. In particular, it is positive that the collaborative work between Ofgem and the DNOs has resulted in a consistent way to measure the reach of companies' Priority Services Registers (PSRs) – and that DNOs' performance against this measure will drive a significant proportion (40%) of the value of the incentive.

It is essential that DNOs hold a comprehensive, accurate and up-to-date list of customers with different types of need, so that they can provide them with additional support in the case of a power cut. This consistent metric should help to clarify the true level of DNO performance in this crucial area. It will also be important for Ofgem to ensure that, in driving for a high proportion of all eligible groups on their PSRs, DNOs do not ignore populations of high-priority customers who may be more challenging to reach.

We also support Ofgem's intention to exclude some categories of service from those that DNOs can offer to customers in fuel poverty or those at risk of being left behind by the energy transition. This should avoid the risk of incentivising DNOs to invest in new skills or services that are already being provided by others. It also provides welcome clarity about what services Ofgem considers it is inappropriate for DNOs to provide, and why. That said, if DNOs in their responses to the DD are able to make a more compelling case for why they are best placed to provide certain services (for example, energy efficiency solutions) in particular situations, then we would encourage Ofgem to consider these.

The value delivered by these services will be measured using a Social Return on Investment (SROI) tool. SROI is a useful tool to help prioritise activities as it recognises the wider benefits to society of different types of investment. However, we expressed concerns in our report that using SROI as the basis for an incentive that drives financial rewards and penalties could skew DNOs' focus away from individuals' need, as well as driving unduly high rewards for DNOs (and so costs for bill payers).

This risk should now be limited by Ofgem's intention for the incentive to recognise value only from services 'delivered via an individual interaction with a customer which is of direct benefit to that customer'. It will be important for Ofgem to satisfy itself before the start of ED2 that this clarification is, indeed, likely to drive DNOs to provide services with the greatest value to customers in most need.

We do, though, have a number of concerns with Ofgem's proposals.

PSR reach

In our report, we flagged that DNOs appeared to have very different proportions of eligible customers registered on their PSRs – and to be setting themselves an equally wide range of targets for improvement. We couldn't be sure of this because DNOs used a number of different ways to measure PSR reach. Now that Ofgem and the DNOs have agreed a consistent approach, this wide variability has been confirmed.

The DD doesn't set out the detail of each DNO's current reach, and the proposed targets for ED2, but Ofgem subsequently shared the following information with us.

Table 2: DNOs' forecast PSR reach by the end of ED1, and their proposed targets for ED2

PSR reach %	ENWL	NPg	SPEN	SSEN	UKPN	WPD
End of ED1 forecast	54	42	70	71	64.7	62
Year 2 target	60	50	74	72	68.9	66
Year 5 target	60	55	80	72	75.2	75

Ofgem has used this data to establish a performance 'dead band'. This means that DNOs would be rewarded only if they achieved a PSR reach above 75% and would be penalised only if they dropped below 50% (and with no additional penalty if they were to drop below 35%). We are concerned that this band is too wide, that the floor is too low, and that it is not appropriate to cap penalties if DNOs' performance falls below 35%. As a result, there is little incentive for the poorer performing DNOs to catch up.

In NPg's case, its targeted performance by the end of ED2 is only in line with the starting position of the second weakest performer (ENWL). If this target is all NPg achieves, it would still leave almost half of NPg's customers in vulnerable situations effectively cut off from vital support during a power cut. We think that Ofgem should set a much tougher minimum standard in this area – either from the start of ED2, or else to take effect after the first assessment milestone (currently due to take place at the end of year 2). As a minimum, lower performers should be penalised for any deterioration in performance.

Support services

We are also concerned by the wide spread of value that Ofgem's DD suggests DNOs may deliver to customers in fuel poverty or who are at risk of being left behind by the energy transition. Ofgem plans to use a Net Present Value approach to measure the direct, social value delivered to customers by the range of services set out in their business plans. Given the wide spread of targets that have been submitted so far, it has asked the DNOs to work with each other and an external consultant to check and provide assurance that they are applying the SROI model in a consistent way. It expects the DNOs to update their targets based on this work before its Final Determinations. However, the provisional targets in the DD show that, by the end of ED2, vulnerable customers of WPD and ENWL may expect to be receiving fuel poverty support services with a net value of c£50-60m, whereas customers of UKPN and SPEN may be receiving a net value from these services of less than £10m.

These are bespoke targets, set by the DNOs themselves. But the 10% margins of over- and under-performance which will trigger rewards or penalties are the same for each DNO. So, for example, UKPN may be rewarded for delivering 10% more value from its fuel poverty support services than its 5-year target of £9.28m NPV. At the same time, ENWL may be penalised for delivering 10% less than its 5-year target of +£60.8m NPV.

Ofgem acknowledges that these value targets 'differ substantially' but suggests that this is 'due to the difference in volume and size of support services being delivered by each DNO due to the varying needs of its regions, prevalence of vulnerability and stakeholder/customer needs'. We have not seen enough evidence to be confident that such a wide range of performance can be justified on the basis of customer need. We think it is just as likely to be driven by a combination of: DNOs' track record of performance in this area; the quality of their network of delivery partners; and the ambition of their

plans. If this wide spread of value remains once the DNOs have confirmed that they are applying the SROI and NPV methods consistently, we think that Ofgem should either: demonstrate that differences in need are, indeed, a key driver of variability here; or should build a mechanism into the incentive which would drive up the performance of the poorer performers over time, with the aim of narrowing this postcode lottery-type gap.

We also note that there remains a significant difference between the DNOs in terms of the extent to which they expect shareholders rather than customers to fund these services. It is difficult to justify why customers should directly fund support of this sort in one area and not in another.

Reach and quality of support in a power cut

In our February 2022 report we said that we were concerned that, even after challenge, there was little detail given in DNOs' plans about how they understand the reach and effectiveness of the support they provide to vulnerable customers during a power cut. We thought that the customer satisfaction survey among PSR-registered customers was not enough to measure quality in this area because DNO scores in this survey are already very high – and yet they acknowledge that there is a long way for them to go to understand and respond to the many different needs of customers in vulnerable circumstances.

We are concerned that there is still no metric in Ofgem's vulnerability incentive which will measure and drive improvements in this critical area. We think Ofgem should identify a viable approach in this area, and redirect some of the 30% incentive value currently ear-marked for customer satisfaction among those receiving fuel poverty and LCT support services to this. We think it is likely that customers who receive valuable support in these areas free of charge will also be satisfied with the service they receive, so the value of this incentive could be more effectively redirected elsewhere. More generally, we are concerned that the 9/10 baseline target for these customer satisfaction scores is likely to be unreliable – and could be too soft - as there is no track record in this area. Using a 'dead band' mechanism around these targets could be an effective way to avoid this risk.

Maintain a safe, secure and resilient network

We have addressed the following Ofgem questions in our response below:

Core Q44. Do you have evidence that customers would be willing to face an increase in their bills to also receive an increase in their reliability, including that they understand the actual cost and how this translates into average power cuts?

Core Q45. Do you have evidence of the cost of reliability improvements and the impact that lowering the revenue cap will have on them being achieved?

Core Q46. What are your views on moving to an asymmetric cap and collar?

Core Q47. Are there alternatives to reducing the revenue cap that you think would better balance increases in reliability and the cost to consumers than reducing the revenue cap?

Core Q48. Do you agree with how we have characterised the operation of the current CML methodology and our reasons for changing the setting targets in line with our CI methodology?

We broadly support Ofgem's revised set of proposals for reliability. However, as with services to consumers in vulnerable situations, we are concerned that consumers will continue to receive a wide range of standards throughout ED2, and that this may be even wider because of proposed changes to Ofgem's target-setting methodology.

In our report on the DNOs' plans, we challenged Ofgem to take a further look at its proposals for reliability. We were concerned that its methodology – and DNOs' response to it – may not always be driving good value for customers. We were also concerned about diverging standards experienced by customers in different network areas, and asked Ofgem to look more closely at whether there are materially different levels of customer support for increased reliability in different regions.

Ofgem's revised incentive proposals

In response to our challenges and other concerns from Citizens' Advice about whether consumers understand the full cost of reliability improvements, Ofgem has set out a number of changes to its original approach. It proposes to

- Cap the rewards that DNOs can earn from the Interruptions Incentive Scheme (IIS) from 2.5% of Return on Regulatory Equity (RoRE) to 1%. It believes that the upside of this incentive will still be enough to incentivise DNOs to make further reliability improvements at a reasonable cost
- In tandem, it has kept the 'incentive rates' the same. These rates effectively set the amount that DNOs are allowed to spend to achieve reliability improvements, and some DNOs have argued that they should be increased. Ofgem says it wants to see strong evidence that consumers will pay much higher prices for further incremental reliability improvements before it would increase incentive rates
- Retain the penalty cap at 2.5% - so that the incentive on DNOs becomes 'asymmetric' with a stronger incentive to maintain current standards than to improve them further
- Engage directly with customers during ED2, and in advance of the next price control, to understand better their willingness to pay for further improvements in reliability, especially if future improvements are likely to come at a 'much higher cost' than those delivered to date. Ofgem makes clear that it may revisit its proposals again if good evidence emerges during the consultation that consumers do, indeed, have a full understanding of the cost implications and still want greater reliability.

We broadly support these proposals. In particular, we support Ofgem's decision to retain a strong incentive to protect current reliability standards. We also agree that Ofgem should undertake its own research into consumer attitudes to reliability, their understanding of the likely full cost of delivering this over time and their willingness to pay for this.

We would encourage Ofgem to start by ensuring it has a full understanding of the extensive research that DNOs have already undertaken in this area, and where any strengths and gaps lie. It would also be valuable to draw on the insights of the independent experts on the various DNO Customer Engagement Groups (CEGs) who have had the opportunity to observe and challenge this work over time.

Most importantly Ofgem must also ensure that its own work is done in a way that allows consumers to give a genuinely informed view in this complex area, and to consider it alongside the many other significant pressures on consumers' energy bills now and in the future.

Risk of an ongoing reliability slow lane

We do have concerns about Ofgem's proposed change to the way it sets targets for DNOs to reduce the total time that consumers lose to unplanned power cuts. Its original plan in the SSMD was to base these ED2 targets on the lower quartile performance of all DNOs. This would mean that the DNOs with the worst relative reliability record in ED1 would have to work much harder in ED2 to catch up with the best - or else face financial penalties. Indeed, SSE (whose customers experience the worst reliability rates of all networks), would potentially have been facing penalties from year 1 because the reliability of the best performing networks is so far ahead. We think this would, nevertheless, have been an appropriate way to ensure greater fairness for consumers in different network regions.

By contrast, the new proposal would mean that targets are based on each DNO's own average performance during ED1. Ofgem says that it will still apply higher 'improvement factors' for the poorer performing networks (which would mean they would still be required to deliver 'greater minimal improvements' compared with the best performing DNOs).

But Ofgem's own modelling in the DD shows that, even with these improvement factors applied, the provisional year 1 target for SSE's networks would be at least 10 minutes lower with the new method than with the original. And, at the end of ED2, SSE would only be targeted to limit consumer lost minutes to 40 minutes (in its Southern region) or 43.7 minutes in Scotland. This compares with an average target across all DNOs of 28.8 lost minutes by the end of ED2, and c18.5 for the best performing networks.

We are concerned that this new proposal will leave the customers of some DNOs in the reliability slow lane to the end of ED2 and well beyond and are challenging Ofgem to think again about how to narrow this gap. We are also concerned that easing targets in this way will mean that some DNOs receive rewards that they don't deserve.

Bespoke outputs and PCDs

Ofgem has proposed the following bespoke outputs and price control deliverables in the Draft Determination. These are:

- ENWL - Borrowdale transformers (ODI-R), Reduced restore time for emergency street works (Dig, fix, go) ODI-F with cap/collar of +/-0.2%RoRE, and Smart Street – PCD for 1000 sites
- NPg – none
- WPD - PCD for commercial fleet transition to non-carbon. PCD adjusted to end of life replacement.
- UKPN - (ODI-F) Collaborative street works at £0.3m per project to cap of 0.2% RoRE, PCD for off gas grid anticipatory investment for 242k customers (£73m baseline allowance, conditional on measuring and reporting framework).
- SPEN – Biodiversity licence obligation – partially accepted.

- SSEN – Licence Obligation to extend life of Lerwick Power Station to 2035

We agree with the proposed outputs, incentives and PCDs, except for Smart Street as discussed below. We welcome that the UKPN off-gas grid anticipatory investment is subject to a PCD but suggest that, similar to an innovation project, effective monitoring and control gateways are needed to ensure that the project is delivered and that the learnings can be effectively shared.

Smart Street

The ENWL proposition is that they should invest an additional £78m to the £18m already spent on Smart Street to deliver claimed benefits of around £450m over the lifetime of the assets, targeting vulnerable customers. ENWL claim that an investment of c.£350 for each of the 250,000 targeted customers will deliver savings of up to £60 per annum.

We consider that future energy savings may be overestimated. ENWL assumes in its cost-benefit assessment that there is no reduction in customer benefits over time, whereas a trend for growth of consumer appliances and devices – for example, LED lighting - that better control voltage and energy consumption will reduce this benefit. Customer appliances that use electricity for heating will not see any benefit from this measure. The assumptions and benefits appear highly uncertain and will depend on many factors including individual customer energy decisions. Consumption evidence was collected in 2015 to 2017 and may no longer be representative.

We note Ofgem agrees with the Challenge Group's February report about concerns that the modelled benefits found in ENWL's CVP proposal may be overstated, and has rejected the CVP claim. Ofgem noted that the ability to reduce energy consumption may deteriorate over the lifetime of the project as LCT uptake increases. However, Ofgem proposes to include Smart Street expenditure of £78m in ENWL's totex baseline as a mechanistic PCD, allowing Ofgem to clawback costs where ENWL deploys Smart Street to fewer than the 1,000 substations proposed.

We suggest the benefits for Smart Street are sufficiently uncertain that it should not be included in baseline but should be treated as a re-opener that may release initial investment after an up-to-date and independent assessment of benefits, and subsequent investment be released through a gateway approval process.

3. Networks for Net Zero – load-related expenditure

Introduction

Ofgem's objective for ED2 is to provide funding to deliver Net Zero at lowest cost to the customer while maintaining world-class levels of system reliability. The regulatory regime aims to balance increased network investment and optimisation of the existing network to deliver efficiencies for customers.

Ofgem proposes four initiatives to prepare the networks to deliver Net Zero. These are:

- **Baseline LRE investment** funding of ~£2.7bn in LRE to support the rollout of electric vehicles (EVs), heat pumps and the connection of more local, low-carbon solar, wind and batteries. Ofgem's baseline LRE allowances are lower than requested by the DNOs.
- **Uncertainty mechanisms** - uncertainty mechanisms that will allow investment to adapt quickly to support higher volumes of low-carbon technologies if networks are faced with sharper uptakes.
- **Innovation funding** – of research and development of green energy through an extension of the Strategic Innovation Fund (SIF) and the Network Innovation Allowance (NIA)
- **Environmental funding** - funding the DNOs to undertake activities to decarbonise the electricity distribution networks and to reduce the wider impact of network activity on the environment.

Setting allowances for load-related expenditure (LRE)

Ofgem acknowledges the twin challenges of ensuring that the networks are not a blocker to Net Zero by having sufficient funding to invest in network capacity and protecting consumers against unnecessary costs by avoiding investment in network upgrades that are not required.

The Challenge Group supports balancing increased investment in new, physical network infrastructure with the need to maximise the potential of flexible technologies that may provide more cost-effective ways of increasing capacity. We believe that this provides significant opportunity to optimise the development and operation of the electricity network and increase efficiencies that can lower costs for consumers.

We support the use of a baseline LRE allowance with automatic uncertainty mechanisms (and associated caps/re-openers) to deliver Net Zero at lowest cost to customers. But, given all the uncertainties about future demand, it is difficult to know how much investment can be accurately forecast and committed in investment plans now, and how much should be subject to uncertainty mechanisms which allow spending to be adjusted in the future in response to actual demand.

Given the wider societal costs of the failure to achieve Net Zero, we consider this is an area where a proactive approach to investment, including anticipatory investment should be taken.

However, the current ED1 price control forecast higher LCT growth and set LRE allowances higher than needed. There is again a risk of this in ED2 and that, as a result, customers face higher bills than necessary. While the proposed LRE baseline funding is lower than that requested by the DNOs, it may

still be too high. It may not reflect potential demand and investment reductions arising from the current energy crisis, nor those available from smart operation and flexibility services.

Indeed, setting the baseline and volume drivers at overly generous levels could undermine DNO incentives to deliver benefits from smart operation and flexibility services. Analysis by Imperial College suggests that these benefits could total some £30 billion by 2030.

Overall, we agree that the proposed baseline based on the 2021 System Transformation demand profile is appropriate, doubling the equivalent investment allowances in ED1. The calibration of the baseline and uncertainty mechanisms, and the other protection mechanisms will need to balance lowest cost delivery with ensuring the pathway to Net Zero is assured.

We have addressed the following Ofgem questions in our response below:

Core-Q3. Do you agree with our proposal to adjust allowances to £2.68bn to account for the concerns highlighted by our assessment?

Core-Q4. Do you agree with our proposed secondary reinforcement volume driver and LV services volume driver and the associated controls?

Core-Q5. Do you agree with our proposed LRE re-opener?

Core-Q6. Do you agree with our proposed approach to the Net Zero re-opener?

a) Setting LRE baselines

Ofgem proposals

Ofgem's proposed regulatory regime aims to balance increased network investment and optimisation of the existing network to deliver efficiencies for customers. Ofgem proposes the following initiatives in relation to load-related expenditure. These are:

Baseline LRE investment - funding of ~£2.7bn in LRE to support the rollout of EVs, Heat Pumps and connection of more local, low-carbon solar, wind and batteries. Ofgem's baseline LRE allowances are lower than requested by the DNOs, derived by adjusting allowances to a consistent Net Zero compliant starting point. This reflects insufficient justification for DNO scenarios and ensures funding is only provided for justified investment.

Ofgem notes that strategic investment will be enabled through the LRE package but, at this stage, DNOs have put forward very little discrete, clearly justified, strategic investment. Ofgem remains open to considering the case for additional strategic investment in baseline expenditure, while this will also be enabled through our uncertainty mechanisms.

Uncertainty mechanisms - uncertainty mechanisms that will allow investment to adapt quickly to support higher volumes of low-carbon technologies if networks are faced with sharper uptakes. Two automatic volume drivers are proposed, for secondary reinforcement and low voltage (LV) services, and an administrative re-opener covering all other LRE

Customer protection - Ofgem also proposes to protect consumers from paying higher costs than necessary by using reporting metrics, a clawback mechanism for unjustified spend and a cap on volume driver usage.

Challenge Group Comments

The Challenge Group recognises the difficulties faced by Ofgem in ensuring the investment needed to achieve Net Zero is delivered efficiently given the considerable uncertainties around

- the network peak demand scenarios during ED2 and the Net Zero pathway, including the need for, and timing of, anticipatory investment
- the potential for enhanced network monitoring and control and for flexibility resources to reduce peak demand and enhance network utilisation.

We discuss these issues in more detail below.

Peak demand scenarios

We note that Ofgem has highlighted concerns with the DNOs' scenario use and the overall evidence for the level of baseline expenditure proposed. Ofgem's assessment highlighted concerns regarding:

- the approach to local engagement and strategic network planning, with some plans not evidencing how local planning had influenced forecasts or that any assessment of the credibility of the plans had been undertaken
- the proposed strategy for managing network utilisation and whether the volumes were reflective of the impact of the increasing demands
- inconsistencies in the assumptions regarding the types of EV charging which will be dominant in a region, and the associated contribution to peak demand, with insufficient justification to explain why
- limited assurances for how DNOs would ensure the significantly larger spending plans would be delivered.

We agree with Ofgem's lack of confidence in DNO scenarios. In our February 2022 report, we also highlighted significant inconsistencies between individual DNO demand forecasts. We noted that there were major differences between DNO forecasts for total demand and also for their heat pump and electric vehicle assumptions. Importantly, there was no clear linkage between these drivers and the need for network investment.

Similarly, there was no clear linkage between peak demand levels in DNO plans and their proposed LRE forecasts. The DNOs each derived different demand and LRE growth forecasts.

To illustrate this, the following tables from our report² compare the range of DNO forecasts with the equivalent period for each of the 2021 FES scenarios over the 2016 to 2028 period. DNO forecasts range from -2% to plus 38% over the same period. The FES scenarios for the same period show peak demand growth ranges between 6% to 10%.

² <https://www.ofgem.gov.uk/publications/riio-2-challenge-group-independent-report-ofgem-electricity-distribution-business-plans>

Figure 1: Comparison of DNO submissions with 2021 FES (demand change 2016-2028)

Peak Demand	Change 2016-28
ENWL	16%
NPg	-2%
WPD	8%
UKPN	2%
SPEN	3%
SSEN	38%
National	9%

Electricity System ACS Peak Demand GW	Change 16-28
FES 2021 Consumer Transformation	10%
FES 2021 System Transformation	6%
FES 2021 Leading the Way	6%
FES 2021 Steady Progression	12%

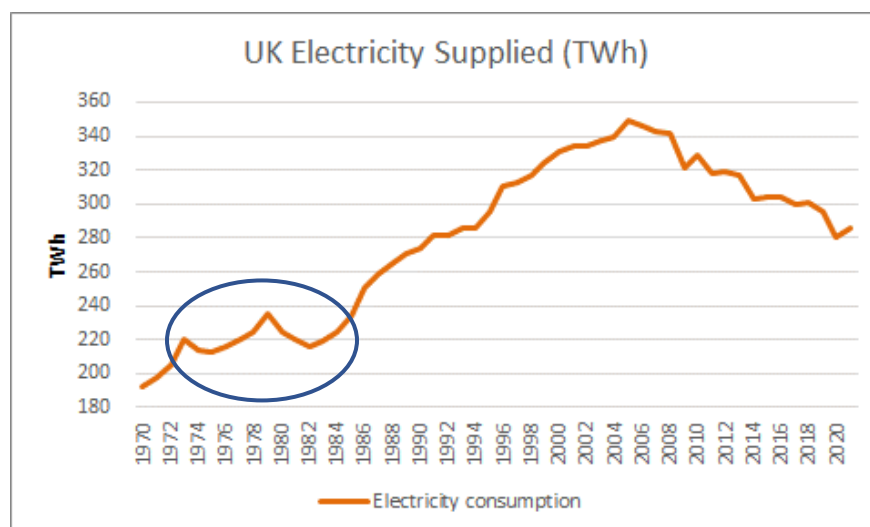
In addition to the lack of clarity and consistency in the forecasts submitted by DNOs, we suggest it is also important to consider the uncertainties associated with the current energy crisis and with the deployment of flexibility.

The current energy crisis

We suggest that Ofgem should also take into account the potential for significant changes to forecast demand that could result from the current energy and cost of living crisis. This crisis has emerged since DNO final plans were submitted and the impact of the current energy crisis is unlikely to have been captured in their future demand forecasts. Recent events may result in a significant and permanent reduction in demand (or ‘demand destruction’) over the ED2 period and beyond.

Looking back over time to similar situations, Government statistics of historic UK electricity consumption³ shows the following profile of energy consumption between 1970 and 2021. The chart indicates two significant and prolonged troughs in electricity demand after the 1972 and 1979 energy crises where high prices/supply constraints were also experienced.

Figure 2: UK Electricity supplied (1970-21)



If similar trends were to take place over the next few years, then DNO peak demand profiles may suffer a similar decline. Even if demand increases from LCT are overlaid, this could reduce demand and the

³ <https://www.gov.uk/government/statistical-data-sets/historical-electricity-data>

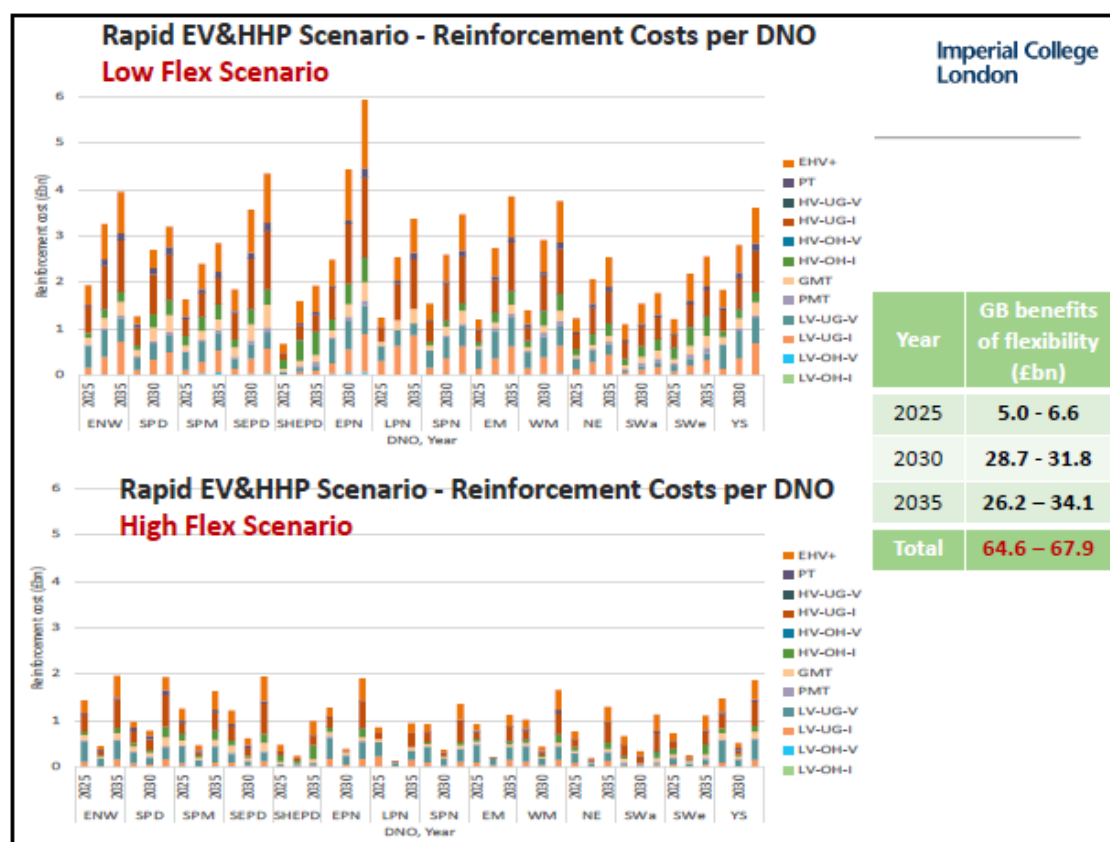
need for network investment below forecast levels. This could add an additional uncertainty which does not appear to have been included in the forecasts that DNOs submitted last year.

Flexibility benefits

Another important factor to be taken into account is the investment reduction benefit gained due to enhanced network utilisation resulting from improved network visibility and control, and from flexibility markets. All DNOs are expecting to release capacity from the deployment of these additional capabilities. But there is no clear linkage in DNO plans between the use of flexibility, the demand profiles and the level of network investment.

The following charts from Imperial College analysis present potential benefits of flexibility in reducing the amount of reinforcement of GB Distribution Networks for accelerated electrification of transport and heat sectors. This analysis shows the benefits of deploying flexibility may be very significant and could reach £30billion, or around £1,000 per customer by 2030.

Figure 3: Flexibility benefits from reductions in DNO reinforcement costs⁴



⁴ (Vivid Economics, Imperial College London: “Accelerated electrification and the GB electricity system”, report to the Committee on Climate Change, 2019, <https://www.theccc.org.uk/wp-content/uploads/2019/05/CCC-Accelerated-Electrification-Vivid-Economics-Imperial.pdf>)

There is a risk that, If DNOs are allowed higher than necessary baseline LRE allowance, they may decide not to deploy flexibility markets or enhanced system control. They may instead consider it is in their interest to invest in assets with long-term guaranteed returns instead of deferring or avoiding expenditure. This may chill flexibility markets and result in customers paying more than they need to.

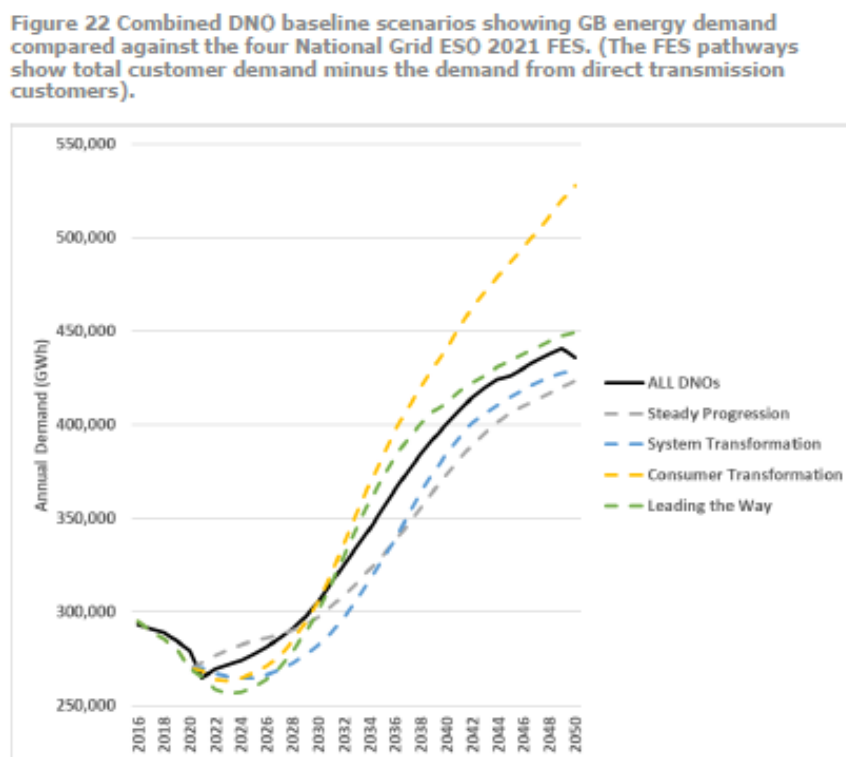
Setting baseline LRE

Given all the uncertainties outlined above, it is difficult to know how much investment can be accurately forecast and firmly committed in investment plans now, and how much should be subject to uncertainty mechanisms which adjust future spending in response to actual demand.

Ofgem’s approach to Net Zero related investment can be summarised as relying on the demand profile from National Grid ESO Future Energy Scenarios ‘System Transformation’ (ST) scenario for baseline allowances, with the use of uncertainty mechanisms for expenditure above the baseline.

As shown below, during the ED2 period, the ST scenario is similar to the higher Customer Transformation (CT) scenario in early years, but the CT scenario shows higher growth in later years. Both are lower than the DNO combined demand scenario. Given the uncertainties about demand forecasts, we agree that using the lower ST demand scenario for ED2 together with uncertainty mechanisms is appropriate.

Figure 4: Demand scenario comparisons from Ofgem DD document



We note there are inconsistencies with using the ST scenario. The demand profile assumes substantial use of hydrogen for home heating. Ofgem’s RIIO2 determinations for the gas networks do not assume the investment needed to make this happen. This is understandable given that a government decision is not due until 2026. This means that baseline allowances across the energy system are below those

implied in ST. Investment in either the gas or electricity networks may need to increase to meet Net Zero, something which uncertainty mechanisms will need to make possible.

The Challenge Group understands the reasons why Ofgem is basing its draft determinations on the ST scenario. Given the extent of uncertainty, a reliance on this scenario and the proposed uncertainty mechanisms is entirely reasonable.

b) Load-related uncertainty mechanisms

Uncertainty mechanism considerations

Alongside baseline LRE allowances, it will be very important to get the design of uncertainty mechanisms right. They will need to balance the need to deliver Net Zero with the need to keep costs to consumers as low as possible. These two aims, and their implications for uncertainty mechanisms, are discussed further below.

On the one hand, the wider societal costs of the failure to achieve Net Zero are such that this is not an area for delaying or cutting expenditure on grounds of short-term affordability. But, on the other hand, there is a risk of setting allowances higher than necessary and handing windfall gains to companies and higher costs to hard-pressed customers.

Delivering Net Zero - To deliver Net Zero, the mechanisms will need to be capable of delivering swift and clear decisions, even though the evidence will necessarily be incomplete. Ofgem may wish to consider where it can source independent assessments of potential need at distribution level, in the way that the Future System Operator should be able to provide at transmission scale, given that Distribution System Operation is less developed and less independent. But ultimately a judgement on the balance of risks will need to be taken.

Technology transitions are not incremental, linear processes. Instead, they follow well established ‘S-shaped’ paths, with relatively slow initial uptake followed by inflection points at which adoption becomes more rapid. This is already underway - for example, with the take up of electric vehicles or renewable electricity generation. However, it appears to be very hard to deliver network upgrades on a S-shaped profile. With both EV charging and renewable generation, constraints on the distribution grid are emerging as serious blockers to progress on Net Zero. This also adds additional costs to consumers.

In some cases, there are clear trigger points, such as a government decision on gas grid conversion which is promised for 2026. But, overall, uncertainty mechanisms need to be designed so that investment decisions are taken before uncertainty is entirely resolved and ahead of inflection points being reached. Uncertainty mechanisms should, of course, be managed as efficiently as possible for customers. These are large sums of money and companies should not be allowed to make windfall gains from their greater access to information.

But there is a risk that high LRE costs may be incurred in future price controls if catch-up becomes necessary ahead of the period covered by Carbon Budget 6. The efficient combination of linear build out of networks and S-shaped take-up of low-carbon technologies implies investment may be needed ahead of the inflection point. This will require decisions to be taken within uncertainty mechanisms based on forward-looking indicators, rather than waiting for uncertainty to be resolved.

It may not be possible to wait for LRE investment decisions until uncertainty is resolved or rely on purely data-driven mechanisms. Nor do the timelines allow for outcome-based regulation, since the outcomes may not be delivered in the same price control period as the investment is needed.

Investment need not be in traditional network upgrades. Flexibility solutions can often offer low-cost alternatives and can potentially be delivered more quickly as well. Where flexibility solutions can defer the need for network upgrades for substantial periods of time, they should almost always be the first choice. Even if they are subsequently overbuilt, the option value they provide is likely to be significant. But where solutions only offer short-term relief, the option value calculation is more complex. The benefits of a few more years of information must be weighed against the risk of exacerbating the effects of the S-curve. In some cases, it may be more efficient to hold some short-term flexibility options in reserve, if they can then be deployed rapidly, since they can potentially mitigate the consequences if S-curves are steeper than anticipated.

Ensuring efficient investment – to deliver efficient expenditure, the mechanisms will need to be capable of adapting to actual evidence arising during the price controls. Lower than expected demand forecasts and lower than expected network utilisation may both lead to windfall gains for companies, and lead to customers paying again for these investments in future price controls.

The expansion of distributed flexibility and local energy solutions has the potential for significantly displacing the need for LRE investment. Indeed, overly generous ex-ante LRE allowances may reduce the incentive for these flexibility resources to be deployed.

The risk of additional, less efficient catch-up LRE being needed in future price controls may not arise. The S-shaped technology transition curve of distribution-connected LCT is uncertain, as is the impact it may have on the need for distribution reinforcement. Voluntary or contractual curtailment of EV charging over peaks for example, may significantly reduce the need for network reinforcement.

Also, expansion of distribution network capacity may be expected to be delivered in significantly shorter timescales than for transmission networks. Current DNO proposals for a ‘one touch’ approach to enhancing network capacity should enable future proofing. Once the assets need to be replaced or reinforced, the capacity of the new cables could be, say, four times larger than maximum demand.

Finally, companies will always have more information than Ofgem has access to when determining their demand forecasts and expenditure needs, and in the design of uncertainty mechanisms. We note that ED1 LRE forecasts were underspent overall, highlighting that the reason was lower than expected LCT rollout. While such expenditure savings were shared with customers, this does mean that DNOs could be funded again for this expenditure and customers will pay again for it.

It is important that the ED2 uncertainty mechanisms address both of these key considerations. Our detailed comments on the proposed uncertainty mechanisms are discussed below.

Ofgem proposals

For RIIO-ED2, Ofgem proposes to manage load-related uncertainty using a combination of automatic mechanisms for lower-value, high-volume interventions including the unlooping of LV services, and an administrative re-opener for higher-value but lower-volume interventions. Ofgem identifies two key risks associated with the automatic volume drivers:

- the risk of overinvestment in network capacity, and

- the related risk of weakening incentives for a 'flexibility first' approach, where flexibility resources and other smart technologies are prioritised by the DNOs in their management of network use before pursuing traditional investment.

To mitigate these risks Ofgem proposes to create a set of controls that tie to an efficient investment needs case and introducing a cap on the volume driver to limit its use. Ofgem also proposes applying the Totex Incentive Mechanism (TIM) to volume driver spend to retain incentives for cost efficiency and protect both DNOs and consumers for any under- or over-spend.

Secondary reinforcement volume driver - This is the most material LRE element within DNO business plans, comprising £1.3bn. Ofgem anticipates that the main driver of secondary reinforcement will be the uptake of EVs which is challenging to predict. The volume drivers are proposed to fund work related to substation and circuit capacity constraints on the secondary network (LV and HV). The scope will apply to conventional solutions for releasing capacity:

- substation: £/MVA gross additions for pole mounted transformers (PMTs) and ground mounted transformers (GMTs)
- circuits: £/km additions with separate unit costs by voltage level.

Ofgem notes that both options introduce a significant risk of gaming and/or windfall gains for the companies. They may also have the effect of reducing the incentive on companies to seek increased utilisation of existing assets through enhanced network operation or commercial flexibility solutions.

LV services volume driver - Ofgem proposes a volume driver for LV services reinforcement, particularly the 'unlooping' of LV service cables. It is output-based, set on a £/asset basis as this provides the most stable unit cost. This volume driver covers:

- overhead Pole Line – LV Service (OHL)
- cable – LV service (UG)
- switchgear – Cut Out (metered)
- fuse upgrades.

Ofgem notes that currently DNOs respond reactively to consumer requests, but this may lead to an inefficient approach or lead to blocking the uptake of LCTs. But some DNOs are proposing a more proactive approach for RIIO-ED2, adopting a street-by-street approach based on local forecasting.

Ofgem proposes to fund both proactive and reactive reinforcement within the volume driver to ensure a more strategic approach and avoid any inefficient, incremental investment. Ofgem proposes to apply the same unit cost to create an incentive to be proactive and drive efficiencies.

Volume driver controls – For secondary reinforcement, Ofgem proposes annual reporting on drivers of investment and a process to clawback unjustified spend and a cap on the total expenditure that can be accessed from the secondary reinforcement volume driver. A mid-period volume driver parameters review is proposed, which would check actual transformer and circuit utilisation, LCT growth and overall demand growth.

LRE re-opener – Ofgem also proposes a re-opener which would apply to all other LRE activities which fall outside the other volume drivers. It is anticipated that these could apply to larger, bespoke projects that may emerge over the price control period.

Challenge group comments

Overall, we welcome the approach that Ofgem has taken to use a combination of baseline allowances and uncertainty mechanisms to fund LRE within ED2. In our view, it is important that this strikes the right balance between delivering Net Zero and protecting consumers from unnecessary costs.

We agree with the use of automatic volume drivers for secondary reinforcement and low voltage (LV) services to address uncertain expenditure in high-volume, low-value load-related interventions and the administrative re-opener covering all other LRE.

Secondary reinforcement volume driver - we agree with the proposed approach but there is insufficient evidence for us to comment on the appropriateness of the calibration of these mechanisms. We agree with Ofgem that it is key to ensure the incentives for flexibility are not weakened by inadvertently incentivising the construction of additional network capacity.

LV services volume driver - we agree that the DNOs need to adopt both a proactive and reactive approach to reinforcement within the volume driver to remove potential barriers to LCT uptake. We also agree that a unit cost volume driver is the most practical mechanism, subject to suitable controls being developed.

LRE re-opener - Ofgem is proposing a re-opener for LRE at higher voltages (primary reinforcement) though, as drafted, this has a broader remit across all LRE. The re-opener is intended for use where additional LRE spend is needed beyond the materiality threshold. We agree that this is a suitable approach to dealing with larger, 'discrete' projects where a more detailed review of the justification and costs is appropriate, as well as giving a mechanism for the implementation of the Access SCR.

Volume driver controls

We think there are four key risks from the automatic volume driver approach.

- First, there is a risk that the mechanisms are set at a level that is lower than necessary to attract DNO investment in these assets, and the pathway to Net Zero is not met.
- Second, there is a risk of higher than necessary parameters leading to windfall gains for companies from the TIM incentive. Experience from past price controls suggests that information asymmetry in the design of the volume driver may mean they are overly generous. In this case, additional revenue allowances are triggered but investment can easily be realised by DNOs at lower expenditure levels, rather than through efficiency savings.
- Third, there is a risk that higher than necessary allowances from these volume drivers leads to investment in stranded assets.
- Fourth, volume drivers may weaken incentives for enhancing existing network utilisation, either from improved operability or from commercial flexibility services.

We welcome the fact that Ofgem proposes to establish effective controls to ensure the volume drivers are used efficiently, and that conventional reinforcement is used only when alternative options have been exhausted.

We also welcome Ofgem's proposals for: annual reporting on investment drivers; a clawback on unjustified spend; and a cap on the total expenditure from the secondary reinforcement volume driver.

A mid-period volume driver parameters review is proposed, which would check actual transformer and circuit utilisation, LCT growth and overall demand growth.

We consider this monitoring-led approach should help to provide appropriate safeguards for customers – and it should provide a step change in the volume of current and forecast network utilisation data that is available. The requirement for accurate utilisation reporting should be a clear licence obligation, alongside the reporting of flexibility information and opportunities.

We welcome the proposals for a mid-period parameters review, including the unit cost and cap, an audit of the DNOs' data submissions for the first half of ED2, and an assessment of progress against the expectation of granular utilisation data be available for ED3. This adjustment should substantially address the risks listed above.

The volume driver cap proposed by Ofgem is set at the level proposed by the CCC Balanced Pathway. We note that the Balanced Pathway suggests that there will be c12m EVs in 2028, which is higher than the DNO upper case forecasts of 9.6m. It is unclear what the implications of this cap choice will be and the effect it may have on expenditure plans. If the cap is set too low, then it may restrict investment. If it is set too high, it may result in the continuation of inefficient volume drivers and windfall gains. We note that it is proposed that the mid-period review should only revise this cap upwards or keep it the same. We suggest that an option to revise downwards is also included.

We are concerned that the design of the automatic volume drivers appears to be based on an expectation that they will only need to trigger increased expenditure. This may not be the case. If forecasts of future demand are reduced as a result, for example, of more efficient than expected network utilisation or changes in expected future demand, then some DNOs may require lower expenditure than the allowed baseline. In this situation, it may be appropriate to have volume drivers that reduce as well as increase allowances.

We acknowledge that these driver controls are still being developed with the RIIO-ED2 LRE working group. We wish to reiterate the importance of developing well-designed and flexible uncertainty mechanisms with strong controls to remove barriers to achieving Net Zero while protecting consumers from excessive costs.

c) Net Zero re-opener

Ofgem proposes to proceed with the introduction of the Net Zero re-opener to address material changes from exogenous factors such as changes in government policy, the role of network companies, or technological or market developments.

We agree with this approach which is consistent with the recent electricity transmission and gas distribution price controls. This approach will help to ensure that ED2 can be adaptable to a wide range of potential developments relating to the transition to Net Zero and does not expose customers to the risk of ex-ante allowances which may not be required.

Innovation

We have addressed the following Ofgem questions in our response:

Core-Q7. Do you agree with our proposed approach to the value of the SIF?

Core-Q8. Do you agree with our proposed approach to weighting SSMD criteria and benchmarking RIIO-ED2 NIA requests against RIIO-ED1?

Core-Q9. Do you agree with our proposed approach to setting NIA allowances?

Core-Q10. Do you agree with our proposal to allow DNOs to carry over any unspent NIA funds from the final year of RIIO-ED1 into the first year of RIIO-ED2?

Ofgem's proposals

Ofgem proposes to support research and development of green energy through an extension of the Strategic Innovation Fund (SIF) to cover the electricity distribution companies and more than £60m of additional allowances to support smaller-scale innovation projects through the Network Innovation Allowance (NIA).

SIF funding

Funding of £450m is available which can increase if necessary.

The aim of the SIF is to support network innovation that contributes to the achievement of net zero, while delivering real net benefits to network companies and consumers; and to work with other public funders of innovation to coordinate with other activities funded by Government.

NIA funding

£66.9m in NIA funding is made available.

DNOs are initially provided with an allowance equivalent to three regulatory years, and projects must start within the first three regulatory years. In 2025, Ofgem would review whether more NIA funding is needed for regulatory years 4 and 5. DNOs would have a use-it-or-lose-it (UIOLI) allowance defined. Ofgem used a number of criteria to determine whether NIA funding should be allowed. It was looking for evidence that DNOs had:

- identified areas in which to target NIA funding that are high risk and in need of ring-fenced innovation stimulus
- made proposals to undertake other innovation as BAU activities during RIIO-ED2
- made proposals that incorporated the application of best practices
- had clear processes to roll out proven innovation into BAU and they are already doing so
- had processes in place to monitor, report and track innovation spending,

In its assessment, Ofgem found three DNOs to have satisfactorily met the five NIA criteria, and the remaining three to have met four of five NIA criteria.

Ofgem highlighted concerns about several DNOs' practices with regards to quantifying and monitoring the benefits from innovation activities. Three DNOs did not provide evidence to demonstrate that they have in place a process to track and monitor innovation benefits, leading to doubts about the robustness of these DNOs' frameworks to roll out innovation to BAU. These concerns led Ofgem to propose a reduced NIA award relative to annual RIIO-ED1 levels for these DNOs.

Challenge Group Comments

We support the availability of innovation funding through the SIF and NIA. This funding of research and development should make a valuable contribution to the delivery of Net Zero at least cost.

We agree with the values proposed for both the SIF and the NIA and the assessment approach used to determine NIA values. We consider it important that appropriate monitoring is in place and there is a clear differentiation from BAU activities that are already funded.

Finally, we agree that unspent funds should be carried over as long as their subsequent application should also meet the five Ofgem tests to assess robustness.

Delivering an environmentally sustainable network

We have addressed the following Ofgem questions in our response:

Core-Q11. Do you agree with our proposed approach for the Annual Environmental Report ODI-R?

Core-Q12. What are your views on the proposed mid-period review on DNO environmental performance and their progress to targets?

Core-Q13. Do you agree with our consultation position for the DNOs' EAP proposals in RIIO-ED2 as set out in this document? (Further detail included in Appendix 1 of this document)

Core-Q14. Do you agree with our proposal to withdraw the Environmental Scorecard ODI-F for RIIO-ED2?

Core-Q15. Do you agree with our proposed approach to design of the Environmental Re-opener?

Core-Q16. Do you agree with our proposal for addressing PCB contamination in PMTs through a volume driver in RIIO-ED2?

Ofgem's proposals

Ofgem is funding the DNOs to undertake activities to decarbonise their networks and to reduce the wider impact of network activity on the environment. This includes efforts to reduce their business carbon footprint, mitigate environmental damage from fluid-filled cables and polychlorinated biphenyls, and gain a further understanding of embodied carbon and supply chain emissions.

Challenge Group Comments

Annual Environmental Report (AER) and mid-period review

The AER will now be the principal mechanism by which companies are incentivised to deliver, and be held to account for delivering, reductions in their environmental impact. We note that more work is being done with the companies on the common format of the AER. We would encourage engagement with those who are most likely to use the reports (CEGS, NGOs, environmental regulators) to ensure that the way data is presented is clear and useful, and that progress against targets is easy to assess.

One of our key concerns about the Environmental Action Plans (EAPs) and business plan environmental commitments was the lack of transparency and consistency in the presentation of targets, and we urge that one of the aims of the further work on the AER format should be to ensure that reporting in key

areas is as clear, consistent, and comparable as possible. We encourage Ofgem, as Sustainability First has proposed, to maximise the effects and benefits of the AER by producing or commissioning its own analysis of the AER data so that stakeholders can use comparative data to challenge the companies more effectively. We also urge Ofgem, as a minimum, to publish annual comparative data in the form of RAG ratings or league tables, to enhance the impact of the reputational incentive of the AERs.

We think the mid-term targets and mid-period review could be particularly useful tools for stakeholders seeking to hold the companies to account, and for development of ED3 commitments and targets. Again, it will be important to ensure that there is consultation with stakeholders so that there is some degree of challenge in the target setting process, and we encourage Ofgem to ensure that the data is subject to some independent comparative analysis. The mid-period review could play a particularly useful role in providing a focus for development of targets and progress in those areas where DNOs will not have set targets before the start of the price control – notably reducing embedded carbon.

EAP commitments and targets

We support Ofgem's position on specific EAP commitments, including encouragement for companies to do more to increase transparency on management of losses, to show ambition in relation to adopting targets for reduction of embodied carbon and to provide further evidence on carbon off-setting. We note that the comparative tables in Appendix 1 to the Core Methodology document reinforce the challenge of making sensible comparisons between plans and targets and the desirability of introducing increased standard expression of targets (see, for example, Table 70 on proposals for managing SF6). Common reporting standards are essential to allow effective comparison of performance and understanding of the effects of impact of different interventions.

The mid-point review could serve a particularly useful role in relation to areas where further work is required and provide a starting point for thinking about expectations for ED3. We are concerned that most companies do not commit to setting a target for the reduction of embodied carbon within the next price control period but are focused on measurement and developing tools. BSI PAS 2080 already provides a clear framework for measuring embodied carbon and an accompanying tool is under development. The framework has been adopted by several leading contractors and by at least one transmission company. This suggests that the DNO ambition in this area is weak and DNOs should be encouraged to show substantial progress by mid-period review.

Other areas which could usefully be highlighted at mid-period review are losses measurement and reduction and SF6 (where we agree with Sustainability First that companies must be encouraged to plan ahead for elimination of SF6 asset banks).

ODI-F

We support the decision to withdraw the balanced scorecard for RIIO-ED2, given the concerns about relatively small materiality, perverse incentives and risk of undue reward or penalty. However, we note that this leaves delivery of environmentally sustainable networks as the one key output area which is not subject to financial incentivisation. We would encourage Ofgem to use the experience of assessment of strategy delivery in other areas during the ED2 period to inform development of an equivalent approach in ED3.

Environmental re-opener

We support the proposed design of the environmental re-opener, including its broad scope, the materiality threshold and that it should be triggered by Ofgem at any time during the price control.

PCB Re-opener We support the proposed time-limited re-opener for PMT replacement, subject to Ofgem receiving the data and evidence required for design of a robust volume driver. In particular, we support the inclusion of provision for upsizing subject to appropriate justification.

4. A smarter, more flexible, digitally-enabled energy system

Summary of our response

A more flexible, digitally enabled energy system will benefit consumers by optimising existing networks and enabling distributed energy resources to reduce electricity costs. Ofgem proposes four key initiatives for RIIO-ED2 to support this goal and to enable the energy system transition.

1. Data and digitalisation - an obligation to publish Digitalisation Strategy and Action Plans and comply with Data Best Practice, as well as including a digitalisation re-opener to increase adaptability relating to data and digitalisation roles and responsibilities
2. DSO regulation - a DSO incentive to drive DNOs to more efficiently develop and use their networks, taking into account flexible alternatives to network reinforcement
3. DSO re-opener - given there is scope for DSO roles to evolve and there are questions about enduring institutional arrangements, Ofgem are proposing a DSO re-opener to reassign costs and outputs if needed within the RIIO-ED2 period
4. Whole system - arrangements to ensure that DNOs take into account the impacts across the whole system in the operation of the distribution networks.

Overall, we welcome the focus placed by Ofgem in this critical area. It offers the opportunity for the UK to lead the world in exploiting this major opportunity to deliver customer benefits. For DNOs and DSOs to successfully enable these benefits, we believe there must be a step change to move away from the traditional approach of managing networks as individual silos. We have provided detailed comments on these specific proposal areas, below. But, these are the key points in summary.

- **Data and digitalisation** – the obligation to deliver data and digitalisation plans is based on individual DNO strategies and plans, resulting in varied effectiveness of delivery. Benefits will be enhanced by ensuring that all are striving for the best performance. We suggest appropriate delivery targets and compliance incentives are needed to ensure that weaker performers are incentivised to improve.
- **DSO regulation** – it is critical that measurable outcomes that benefit consumers, and associated incentives are put in place. While we consider the proposed performance regime is appropriate, the strength of incentive does not appear strong enough to drive the fundamental change in behaviour that will really put ‘flexibility first’. We have suggested some potential options for enhancing the performance metrics and incentives.
- **DSO re-opener** – we agree that this will be required to address potential changes needed due to changes to roles and responsibilities. But we suggest that it is also used to adapt the required performance targets and appropriate incentives to ensure they are fit for purpose.
- **Whole system** – we welcome the proposed licence obligation for strategic plans as a way of ensuring that more integrated local planning takes place. But we suggest that such plans also focus on options for relieving immediate network capacity constraints – for example, through flexibility as well longer-term network investment.

Data and digitalisation

We have addressed the following Ofgem questions in our response:

Core-Q17. Do you agree with our proposal for implementing a Digitalisation Licence Obligation?

Core-Q18. Do you agree with our proposal to have staggered publications of Digitalisation Strategies between RIIO-ED2 and RIIO-2 licensees?

Core-Q19. Do you agree with our proposed Digitalisation re-opener?

Core-Q20. Do you agree with the proposed enhanced reporting framework associated with IT/OT Data and Digitalisation spend and DSAP investment proposals?

Core-Q21. Do you agree with our proposal to adopt TBM as part of the RIGs/RRP?

Core-Q22. Do you agree with our intention to modernise the regulatory reporting process?

Core-Q23. Do you agree with the proposed timeline for implementation of this modernisation?

Ofgem's proposals

Ofgem expects that data and digitalisation will drive system-wide benefits for the electricity sector in terms of increased efficiencies and by enabling innovators to access the data they need to deploy novel business models including demand-side response and the deployment of low-carbon infrastructure.

Ofgem states that it is confident that DNOs are proposing system architectures that incorporate both the necessary data platforms and data processes needed to improve their digital capabilities and seek to enable services required by the overall energy system. This includes the capability to capture, triage and publish network datasets, noted by the Energy Data Taskforce as a key requirement to deliver a digitalised energy sector.

Ofgem considers that its review of the data and digitalisation proposals and associated CBAs indicates that they appear to offer value for money, with benefits to consumers, the sector, and the DNOs themselves being delivered during RIIO-ED2 and with substantial benefits realised in RIIO-ED3 as the deployment of low-carbon technologies increases significantly.

Ofgem's specific proposals for data and digitalisation are:

- **a digitalisation Licence Obligation** in RIIO-ED2. The purpose of this Licence Obligation is to require the DNOs to make their intentions and plans for digitalisation of their energy network and associated services for data publicly available, and to comply with Data Best Practice
- **a 'digitalisation' re-opener** in Year 3 of the RIIO-ED2 price control. There is significant uncertainty associated with the future digital energy roles and responsibilities for DNOs and so with the digital products and services they will be required to deliver. This proposed re-opener will allow DNOs to change their IT and digital estates in response to emerging changes in the structure of the UK energy sector
- **requiring DNOs to use the Technology Business Management (TBM) Taxonomy** to report on their IT and digital estate during the price control. The taxonomy will provide enhanced transparency and comparability across the DNOs' information technology, operation technology, and data and digitalisation spend

- **an innovation project to test modernisation of the regulatory reporting process.** This innovation project will aim to simplify and develop more cost-effective regulatory reporting. If successful, Ofgem intends to implement any changes to the regulatory reporting process in Year 3 of the price control.

Challenge Group Comments

We welcome Ofgem's policies to enable DNOs to modernise their internal data processes and capabilities to provide efficiency gains, and to provide stakeholders and consumers with key digital services to drive value across the energy system. These will be critical deliverables during ED2, and it will be important that Ofgem is able to monitor progress in achieving both key objectives.

Turning to the specific policy proposals for data and digitalisation, we agree with the introduction of a digitalisation Licence Obligation, including the use of the TBM taxonomy for monitoring. We welcome that there will be increased transparency and comparative information available about DNO IT expenditure.

It will be important that individual DNO digitalisation expenditure and performance against plan may be monitored and compared. In this regard, we have been unable to identify the allowed DNO IT expenditure, scope, and deliverables from the Ofgem DD documents that correspond to the c£890m in DNO business plans. We suggest this is included in the FD such that expenditure and deliverables may be transparent and monitored.

But there is a risk that individual DNO digitalisation approaches – for example, for flexibility or whole system services, result in bespoke 'silos' which hamper the use of data by third parties, including the ESO. We suggest that the digital Licence Obligation should require outward-facing IT systems to be easily accessible to third parties using consistent interface arrangements. This should prioritise effective engagement with the ESO for provision of system management and flexibility services.

We note that the DD comments that individual DNO data and digitalisation proposals appear to offer value for money. While each DNO plan may have provided adequate justification for its individual expenditure, the combination of six different approaches and different levels of maturity may present barriers - to the development of common flexibility markets, for example. This may not provide value for money overall but we recognise the importance of ensuring that baseline funding is provided to ensure data and digitalisation can proceed without delay.

We welcome the proposal for a digitalisation re-opener in Year 3 of the price control. We agree that there is significant uncertainty about the future roles and responsibilities of DSOs and how they are contributing to the delivery of whole-system digitalisation benefits. We suggest that this re-opener should also consider the effectiveness of data and digitalisation expenditure and delivery by each DNO as well as changes to scope and responsibilities. It will be important that the re-opener does not result in additional funding for failed IT system delivery or cost overruns.

Finally, we welcome Ofgem's proposals for the improvement and modernisation of the regulatory reporting process. We would suggest that this should prioritise the reporting of new activities associated with DSO performance and deliverables, together with whole system delivery activities. Wherever possible such reporting should be made publicly available in a readily-accessible form.

Regulating DSO functions

We have addressed the following Ofgem questions in our response. Our following comments firstly address the proposed DSO regulatory framework, and secondly the proposed incentive mechanism.

Core-Q24. Do you agree with our proposed design of the DSO incentive?

Core-Q25. What are your views on the outturn performance metrics and RRE we are proposing to include in the DSO incentive? If you do not support their inclusion, please outline which alternative outturn performance metric(s) or RRE you think should be included in the framework instead.

Core-Q26. Do you agree with our proposal for the DSO re-opener?

a) Ofgem's DSO regulation proposals

Ofgem proposes that RIIO-ED2 should represent a step change for Distribution System Operation (DSO), with DNOs required to deliver enhanced and, in some cases, entirely new DSO functions and services. Flexibility market development and improved LV network visibility are identified as key areas of focus, together with the need to focus on outcome-based measures, such as the customer benefits from reduced network investment costs or reduced system balancing costs.

In the DD, Ofgem identified the following challenges with the DSO strategies.

- The benefits associated with the delivery of the strategies are often not well evidenced. It has concerns about the level of ambition and the extent to which, for example, DSO benefits will be realised through interaction with the ESO. It is also often not clear if the benefits are attributable to the actions of a DNO as opposed to other energy market developments.
- Forecast distribution flexibility procurement also varies significantly across the DNOs, with marked regional disparities. This information provided in the business plans was inconsistent, requiring extensive engagement with the DNOs to understand projections across different years/flexibility products.
- There is also an inherent risk that DSO functions and services could, by virtue of their being developed by DNOs, be centred on distribution network issues and create barriers to third-party participation in markets.

Ofgem proposes that a regulatory and incentive framework for DSO holds the DNOs to account on delivering against the baseline expectations. New reporting requirements under Standard Licence Condition 31E (C31E) are proposed to improve reporting consistency going forward.

Finally, Ofgem proposes that there should be a re-opener to amend the price control in response to changes in the roles and responsibilities of the DSO during the regulatory period.

Challenge Group Comments

We agree with Ofgem that RIIO-ED2 should represent a step change for Distribution System Operation (DSO), with DNOs required to deliver enhanced and, in some cases, entirely new DSO functions and services. As such, it will be important that targets and performance measures are clearly defined and barriers to flexibility markets and whole-system solutions are removed.

Effective arrangements are needed for DSO coordination across the whole energy system to exploit the benefits of flexibility ensuing from efficient DSO and digitalisation developments. In our February report, we highlighted the importance of plans demonstrating customer benefits in the following ways.

- **Network visibility** – enhancing network visibility, both of capacity and utilisation and they are exposing that data to third parties.
- **Local flexibility solutions** – enhancing network control and management, including active network management and flexibility markets with distributed energy resources to enhance utilisation and resilience. They are reducing their network investment needs.
- **National market solutions** – enabling distributed energy resources to participate in national network flexibility markets, and in other balancing and energy markets.
- **DSO plan delivery** – a robust plan for DSO delivery and benefit realisation.
- **Digitalisation** – integrated digitalisation plans with implementation of DSO functions.
- **Whole-system benefits** – demonstrated by engaging with the national electricity system via ESO and with customer (behind the meter) resources, including in the areas of heat and transport.

We identified significant differences between the plans and how they proposed to deliver these activities and associated benefits. We raised a number of generic concerns about DNO plans in our report, including:

- **Energy market barriers** – the DNO proposals for flexibility markets appear to focus primarily on their own network congestion issues. There is a risk that creating new, potentially real-time markets for this purpose puts control infrastructure and governance in place, which inhibits access to price signals by customers wishing to participate in potentially much larger volume energy flexibility markets. New network-centric flexibility markets may have the perverse effect of chilling investment in distributed energy resources and restricting benefits from potentially more valuable demand response assets.
- **Governance arrangements** – we have concerns about the governance arrangements proposed for DSO activities, and the risk that DSO activities are developed for DNO network business self-interest.
- **Benefit delivery** – DSO benefits will be delivered through integrated digitalisation and DSO plans. We found most of the plans gave little confidence that benefits from DSO investments could be measured or delivered. We suggest that measures of DSO benefits could identify improvements in network utilisation and volumes of distributed energy resources traded across all energy markets.
- **Enhanced network resilience and utilisation** – the introduction of enhanced DSO capabilities offers significant benefits that may be gained from greater use of network control to use untapped demand-side resources and dynamic ratings of networks. We found limited evidence that DNOs were seeking to deliver these benefits.
- **Whole system co-ordination** – there are six different DSO strategies proposed by the DNOs and the pace and scope of planned developments appears to differ considerably. Overall, based on the information provided so far, we are concerned that the DSO initiatives may be network-

centric, narrowly-focussed and uncoordinated, putting the potential benefits at risk. Also, the development of six different IT systems, or seven if the ESO system is included, may result in wasteful expenditure if incompatibilities need to be addressed in future.

Overall, we welcome that Ofgem has recognised these issues in developing its DSO policies, including the recent consultation on local energy system governance. But we suggest that delivery by DNOs can only be realised by putting an effective regulatory monitoring and incentive scheme in place. Our comments on the proposed DSO incentive framework follow below.

Turning to the Ofgem proposals in more detail, we note that Ofgem proposes to accept most of the DNOs' DSO strategy proposals and costs without amendment. Ofgem considers that DNOs have articulated their DSO transition and have put forward coherent proposals to address them in RIIO-ED2, including data visibility and facilitating flexibility to develop more economic and efficient solutions to network reinforcement.

While we welcome the baseline funding commitment to the delivery of DSO capabilities and the associated benefits, we are concerned that individual DSO strategies (as currently defined in their plans) offer differing ambitions, costs and confidence in delivery. We consider that some DSO plans are more efficient and effective than others.

DSO expenditure plans

The proposed overall DSO totex for ED2 totals c£890m. Ofgem notes this is a four-fold increase from the equivalent expenditure in ED1. Delivery of the planned activities may be challenging. For example, across all DSOs, there is also a five-fold increase in headcount which may present challenges in training and recruiting the specialist staff.

In our February report, we included the following table which shows the different levels of DSO expenditure proposed by DNOs.

Table 3: DSO costs as presented in business plan data tables

	ED2 DSO totex (£m)	2028 peak MW	£m/ 2028 MW
ENWL	35	4,899	7,149
NPg	90	6,662	13,439
WPD	261	15,079	17,276
UKPN	224	15,138	14,788
SPEN	186	6,871	27,112
SSEN	93	10,223	9,134
Total	889	58,872	

We note that there is a significant variation in DSO totex between companies when allocated in proportion to peak MW. While some of this may be explained by cost allocation differences, we remain concerned that DNOs have adopted different approaches which may not lead to delivery of outcomes or value for money.

We would suggest that Ofgem should clearly define the efficient individual DSO costs to be allowed, with a clear linkage to DSO delivery and benefit realisation targets.

DSO Benefits

The key benefits from DSO investment are expected to be from the application of flexibility as a substitute for network reinforcement, and from enhanced network utilisation resulting from improved network monitoring and control.

The following table, from our February 2022 report⁵, shows the target annual flexibility MW for each company as a % of 2028 peak demand, and the direct LRE savings for ED2 identified in the plans through the implementation of DSO smart control and flexibility measures.

Table 4: DSO flexibility benefits as presented in DNO plans

	DNO 2028 peak MW	2020-28 peak MW increase	DNO ED2 flex forecast (MW)	% flex of 2028 peak MW	2020-28 MW increase	DSO and flex savings (£m)
ENWL	4,899	759	1379	28%	182%	249
NPg	6,662	554	138	2%	25%	155
WPD	15,079	1842	610	4%	33%	94
UKPN	15,138	1822	732	5%	40%	601
SPEN	6,871	558	550	8%	99%	370
SSEN	10,223	3222	5000	49%	155%	18-46
Total	58,872	8757				

The table shows a wide range of claimed flexibility targets and savings. But the figures appear inconsistent and may not be based on a consistent approach to costing the value of savings. Ofgem should ensure that these are put on a comparable basis. Capex savings also appear to total around £1.5bn, which is about 50% of the planned load-related capex across all companies. This appears inconsistent with baseline load-related expenditure levels. It will be important that flexibility performance and benefits have clearer metrics to assess performance.

Valuing flexibility performance

As noted, above, across all DNO plans, there does not appear to be a consistent way of measuring or valuing flexibility. As such, we are concerned that this leads to sub-optimal investment or flexibility decisions being made. We suggest that a common approach to defining and assessing DNO targets and flexibility benefits should be defined alongside the proposed expenditure plans.

In considering this further, we note that the DNOs currently publish their historic flexibility performance on the ENA website⁶. We have reproduced the July 2022 update below:

Figure 5: Extract from July 2022 ENA flexibility report

“Figures published by Energy Networks Association (ENA), which represents the UK and Ireland’s energy networks businesses, show that in the past 12 months 3.7GW¹ of distribution network flexibility has

been tendered, an increase of 31% since last year, and a 76% increase since 2020². This is set to increase further in the coming year.

⁵ <https://www.ofgem.gov.uk/publications/riio-2-challenge-group-independent-report-ofgem-electricity-distribution-business-plans>

⁶ <https://www.energynetworks.org/newsroom/britain-breaks-flexibility-records-for-four-years-running-almost-4gw-tendered-in-12-months>

This year's current tendered flexibility will enable networks to free up almost 4GW of capacity to manage network congestion. That is the equivalent of supporting the connection of over half a million 7kW electric vehicle charge points, or providing electricity to over four million homes across the UK, with no new cabling required."

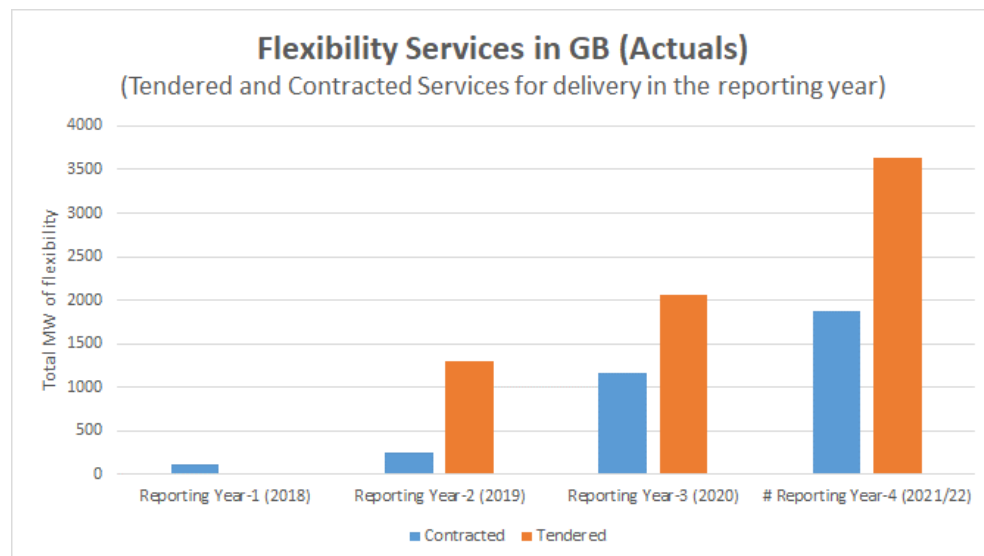
Contracted and Tendered Flexibility data

Year	Contracted	Tendered
Reporting Year-1 (2018)	116	0
Reporting Year-2 (2019)	256	1306
Reporting Year-3 (2020)	1166	2065
Reporting Year-4 (2021/22) #	1867	3635
*As on July 2022/23	1091	3203

Reporting cycle moved from calendar year to regulatory year

The following chart is reproduced from the same ENA flexibility report, showing the growth in flexibility tenders and contracts over recent years.

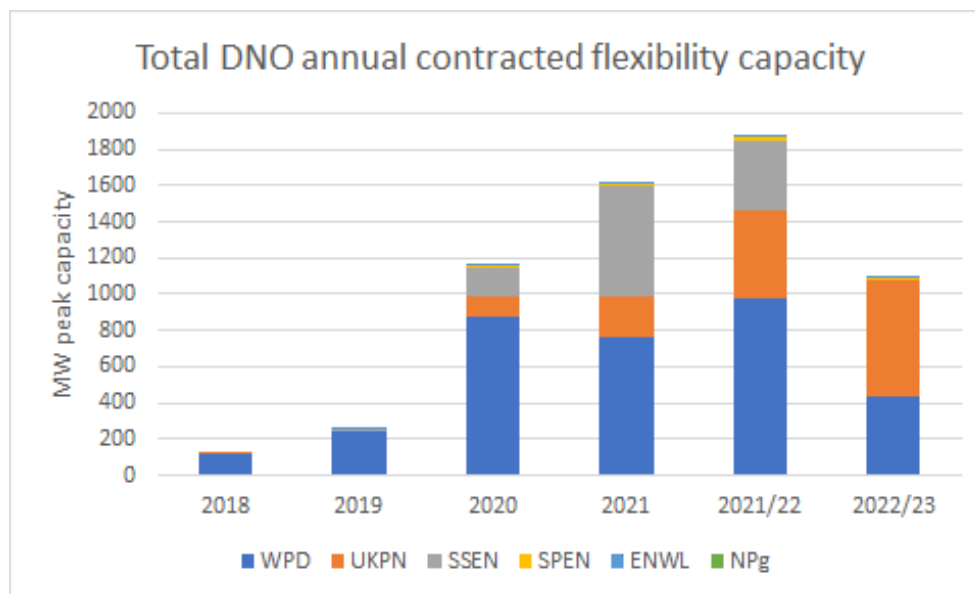
Figure 6: DNO annual contracted dynamic flexibility capacity



This report claims that current year flexibility tenders deployed by DNOs will free up some 4GW of capacity. If this occurs and the growth profile of flexibility benefits increases further over ED2 following DSO investment, then significant additional network capacity may be released. This could significantly reduce the need for reinforcement expenditure, thereby enabling Net Zero at lower cost.

We have also compared the historic performance of DNOs in contracting for flexibility. From ENA published data, we have compared the flexibility contracts by company. It shows that UKPN, WPD and SSEN have been most active in letting contracts, while NPg, SPEN and ENWL are the least active.

Figure 7: DNO annual contracted flexibility capacity



Flexibility will be critical for optimising networks to both increase utilisation and enable Net Zero. For the full benefits to be realised, it will be important for comparative performance to be taken into account as well as the targeting and measurement of overall benefits.

b) DSO financial incentive framework

Ofgem proposes to introduce a new DSO incentive (ODI-F) to drive DSOs to more efficiently develop and use their network, taking into account flexible alternatives to network reinforcement. The benefits are expected to be reduced costs due to deferred or avoided network investment.

The proposed DSO incentive value is +/- 0.2% of RoRE per annum. Ofgem considers that it represents a proportionate level of risk/reward for companies given the scale of DSO investment planned for RIIO-ED2 and the level of ambition set out in the DNOs' DSO strategies. A symmetric incentive is proposed so the penalty associated with failing to meet the baseline expectations should be proportionate to the reward available for exceeding them.

The proposed incentive weightings are:

- **Stakeholder survey (40%)** – stakeholder satisfaction is assessed against a common ex-ante target. The survey is conducted independently, with a target of 7.7/10 proposed (based on the ESO survey track record). A cap of 9/10 and a collar of 6.4/10 is proposed. It is proposed to ask stakeholders annually about their satisfaction with DSO activities in relation to:
 - coordination of DSO activities with other parties, including ESO
 - provision of frequent and accurate operational and planning data
 - flexibility services, markets, and contracts
 - DNO decision making, including conflicts of interest
 - communication and engagement.

- **Performance panel assessment (40%)** – a performance panel undertakes a holistic ex-post evaluative assessment of company performance against ex-ante targets.
- **Outturn performance metrics (20%)** – outturn performance measured against ex-ante company specific metrics. The following metrics are proposed:
 - **flexibility market testing** – the extent of assessments to assess if flexibility solutions are more economic than investment. This would monitor DNO compliance with their Licence Obligation (SLC31E) to flexibility first when considering reinforcement schemes across all voltage levels. As a Licence Obligation, this may be penalty only.
 - **network visibility** – the extent to which there is real-time monitoring of LV network data
 - **curtailment efficiency** – extent of curtailment of non-firm connections.

We note that company specific targets and DSO incentive guidance will be published later this year.

Challenge Group Comments

We welcome the focus that Ofgem has placed on the incentivisation of DSOs and the benefits that they can help realise. However, we are concerned that the proposed incentive design and associated measures of performance may be insufficient to gain the benefits available from this critical area.

In our February 2022 report, we suggested that any performance incentives be based on measured outcomes such as customer benefits from reduced network investment costs or reduced system balancing costs. Other measures could identify improvements in network utilisation, network visibility, and volumes of distributed energy resources traded across all energy markets.

We are concerned that Ofgem’s proposals for DSO incentives may not have the desired effect. The stakeholder survey is untested and may not effectively compare performance across DSOs, unless common stakeholder groups are targeted. The outturn performance metrics are welcome but we would suggest that these are measures of inputs rather than outputs. We suggest output metrics should be enhanced – for example, by including evidence from flexibility tenders. If they can be enhanced, then we suggest these should be a larger proportion of the incentive framework.

While a ‘flexibility first’ commitment is welcome, a step change is needed to optimise DNO network operation and enable distributed energy resources to participate in both local and national flexibility and energy markets. Greater volumes of these resources will deliver greater benefits in optimising the energy system – DSO flexibility offers an important route to seeding this market.

It is critical that the DSOs are incentivised to deliver outcomes that are both valuable to customers and are measurable. We suggest that DSO incentives should be targeted on the following measurable outcomes:

- improved utilisation of networks in congested areas
- the volume of contracted flexibility resources
- capex savings that are realised from these contracted flexibility resources.

To achieve targets based on these metrics, we suggest that the proposed DNO incentive arrangements should be strengthened. There are a number of options that could be considered.

- **Extend the incentive range** - the range of the DSO incentive could be increased, say to +/- 0.5% or perhaps an asymmetric +0.7%/-0.2%. But given that the current proposals for performance measures are not based on clear targeted outputs or benefits, an increased incentive range that is difficult to measure may be difficult to apply and not have the desired incentive effect.
- **Link flexibility and LRE capex incentives** - an alternative may be to address the potential internal conflict that a DNO may have about whether to invest and gain asset returns or seek a flexibility solution. In this case, the Totex Incentive Mechanism (TIM) sharing factor for savings in load-related capex investment could be applicable only if it was demonstrated that a flexibility solution had been used. This could be linked to the new DSO regulatory reporting proposals.

We recognise that turning off this incentive for normal LRE capex could incentivise DNOs to deliver baseline capex volumes even if they were not needed. But, given the expected future capacity needed for Net Zero, this could be regarded as anticipatory investment that consumers would benefit from in future.

This approach of adding a TIM incentive to DSO incentive could significantly increase the incentive available to companies from DSO and flexibility incentives. It should also have the effect of accelerating the growth and liquidity of flexibility markets.

- **Introduce comparative performance incentives** – the proposed incentive regime rewards DNOs against their individual ex-ante targets rather than the overall benefits they offer to consumers. We suggest that it may be appropriate to combine some of the overall DSO amounts and make this available to reward or penalise DNOs against a comparative ranking.

This approach could be deployed by requiring the proposed performance panel to carry out a comparative assessment of each company's performance, or by adapting the stakeholder survey so it allowed a comparative assessment to take place.

These suggestions could be adopted in isolation from, or combined with, the existing Ofgem proposals. If it proves not to be possible to introduce such approaches at the start of ED2, we suggest that the application of such alternative incentive regimes be kept under regular review and included as part of the proposed DSO re-opener arrangements.

Whole system

We have addressed the following Ofgem questions in our response:

[Core-Q27. Do you agree with our proposal to introduce a new whole system strategic planning Licence Obligation?](#)

[Core-Q28. What are your views on the digital tools that could be used to support this?](#)

Ofgem whole system proposals

Ofgem proposes to allow baseline funding for the whole system activities put forward but recognises that the differing levels of ambition and engagement across DNOs means that some areas may develop more slowly than others. Ofgem expects to see DNOs intensify their progress in this area, participating fully in cross-utility planning led by the local authorities.

Ofgem proposes that the main barriers to whole system development raised by stakeholders - such as visibility of data across all energy sectors for local authorities, are being addressed through the data and digitalisation strategies, the DSO strategies, and the ENA's developing work on data platforms for local authorities.

In addition, Ofgem is proposing a new licence obligation which requires DNOs to produce an annual whole systems strategic plan on their approach to decision making, and how they consider whole-system outcomes and report whole-system benefits. This will require the sharing of all input assumptions and planning outputs in an open, interoperable format. Ofgem will issue further guidance for DNOs about this licence obligation in due course.

This Whole System Strategic Plan is expected to give greater transparency on how whole system considerations impact decision making, as well as improved information sharing between DNOs and other local actors. It is expected to provide a more systematic and analytic approach to how to use that information to inform decisions, especially the whole systems assumptions and considerations. It may identify areas for planned network upgrades, future needs and opportunities for flexibility, and conditionality of, and locations where future upgrades may be needed.

Challenge Group comments

The Challenge Group strongly supports the development of a more coordinated whole energy system both to deliver cost efficiencies and to enable the energy transition. Increasing visibility and coordination across the whole energy system can reduce the cost of achieving the energy transition while maintaining energy security and resilience.

In our February 2022 report, we highlighted the importance that DNOs engage beyond their own network/investment plans into the needs of their customers (including beyond the meter), into ESO and national electricity markets, and into the heat and transport vectors. We looked at the internal and external actions that companies were taking to support this transition.

One of the big challenges will be associated with managing synergies and conflicts between local district and national level objectives when allocating flexibility. Addressing this challenge is very important for supporting optimal development of the future system, which is the core objective of the DSO-ESO coordination.

As demonstrated in recent studies, national level benefits of local flexibility could be two times larger than the benefits at the distribution level. In this context, it would be appropriate to establish a stronger plan for DSO-ESO coordination, including stronger links with other energy sectors and organisation (local authorities, heat and transport sectors etc), in the context of the operation and planning of future distribution networks.

We welcome the fact that DNOs' plans have proposed strategies and activities which should help realise whole-system benefits. All have proposed to increase their engagement and co-ordination with external stakeholders. But we are concerned that there are very different levels of ambition and, most importantly, there are few performance measures and output targets arising from these activities. There is a risk that DNOs take a reactive approach to whole-system initiatives, with ineffective engagement with ESO, local authorities, and other stakeholders.

As such, Ofgem's proposal to fund all DNO whole system plans as baseline without such measurement means that strong and weak performance will be difficult to identify and so scope to encourage improvement will be limited. We would suggest that appropriate measures of performance and incentives are established, perhaps combined with DSO incentives, and focusing on whole-system outcomes wherever possible.

Turning to the proposal for a Strategic Planning licence obligation, we support this initiative as a way of ensuring that more integrated local planning takes place. We suggest that the proposed guidance provides specific deadlines for DNOs to deliver the strategic plans for each local government authority or authority group, against a clearly defined scope. We suggest such plans focus on options for relieving immediate network capacity constraints, for example, through flexibility as well as longer-term network investment.

With regard to digital tools needed for live information sharing, we agree it is important that both planning and operational capacity information is available to aid flexibility market development. Such information should be available in a consistent way across DNOs, rather than having six different bespoke systems and interfaces which will present cost and access barriers to market participants.

5. Delivering at lowest cost to energy consumers

A critical element of the ED2 price control is setting totex allowances for DNOs. Total DNO submitted totex for RIIO-ED2, post cost exclusions and reallocations, and excluding RPEs, ongoing efficiency, non-controllable and pass-through costs, is £25.2bn.

Ofgem's view of modelled totex is £23.2bn before post-modelling adjustments, catch-up efficiency and ongoing efficiency are applied. This represents an 8% reduction between Ofgem's modelled totex and DNOs' submitted totex, post normalisations and adjustments.

In addition, Ofgem has applied a post modelling adjustment to bring demand profiles onto a common base, which reduces totex by a further 3%. A catch-up efficiency challenge gives an added downwards adjustment of 1% and an ongoing efficiency challenge drives a further reduction of 5%.

The final proposed totex of £20.9bn represents an overall reduction from DNO submissions of £4.3bn or 17.1%.

Overview of our response

In our February 2022 report, we compared company plan submissions with their current run rates for ED1. We noted that the company totex forecasts bid for a major increase from ED1 levels of expenditure, seeking an increase of some 30% overall in baseline expenditure.

While we observed that increases may be expected in load-related expenditure and in DSO initiatives, we were concerned that the overall increase being sought was much higher than might be expected, given that the underlying DNO network activities remained largely the same.

Overall, we welcome the approach that Ofgem has taken to assess the justification and value for money of DNO proposed expenditure plans, resulting in a 17% aggregate cut in expenditure from DNO submissions. We have provided our detailed comments on Ofgem's consultation questions about totex proposals later in this section.

We have also compared Ofgem's DD proposals with the current expenditure run rates for ED1. The following table shows the average annual ED1 expenditure for each DNO group and major cost category, taken from our February 2022 report. We have used the ED1 annual average expenditure to calculate a 5-year ED1 total to compare with equivalent ED2 5-year totals (all figures are in 2020/21 prices).

Table 5: ED1 annual average and 5-year equivalent totex figures⁷

	ENWL		NPg		WPD		UKPN		SPEN		SSEN		Total	
	Average	5 Yr equiv.	Average	5 Yr equiv.	Average	5 Yr equiv.	Average	5 Yr equiv.	Average	5 Yr equiv.	Average	5 Yr equiv.	Average	5 Yr equiv.
Load related capex	15	74	26	130	95	474	69	343	46	229	37	186	287	1434
Non load related capex	89	447	161	807	335	1675	201	1007	178	892	160	802	1126	5629
Non operational capex	12	58	19	95	51	256	37	184	12	62	26	130	157	785
Network operating costs	58	288	119	596	241	1206	214	1071	99	493	122	609	852	4262
Closely assoc. indirects	52	260	85	423	237	1184	205	1025	114	569	132	658	824	4119
Business support costs	36	179	49	243	99	493	89	446	70	349	71	354	413	2063
Total	261	1306	459	2293	1058	5288	815	4076	519	2593	548	2738	3659	18293

A comparison is then shown, below, for individual DNOs and in aggregate for the major cost categories. It shows the percentage change between ED1 and ED2 expenditure, using the ED1 annual average expenditure to calculate a 5-year ED1 total to compare with equivalent ED2 totals.

⁷ <https://www.ofgem.gov.uk/publications/riio-2-challenge-group-independent-report-ofgem-electricity-distribution-business-plans>

The ED2 proposed totex shown below (£20,937m) includes the demand driven adjustment, catch up efficiency and ongoing efficiency. There are minor differences with the equivalent Ofgem draft determination allowance total (£20,939m) due to rounding errors.

Table 6: Comparison of totex proposals with ED1

	% ED1 - ED2 change						ED1 equiv totex (£m)	ED2 submitted totex	ED2 Proposed Totex	% change from ED1 to DD	% change from BP submission
	ENWL	NPg	WPD	UKPN	SPEN	SSEN					
Load related capex	243%	289%	62%	58%	63%	108%	1435	3415	2825	97%	-17%
Non load related capex	16%	-5%	0%	23%	13%	26%	5628	7548	6219	11%	-18%
Non operational capex	31%	34%	63%	65%	131%	33%	786	1492	1242	58%	-17%
Network operating costs	-10%	-18%	-26%	-17%	-7%	-8%	4262	4254	3541	-17%	-17%
Closely assoc. indirects	26%	21%	3%	33%	10%	17%	4120	5773	4816	17%	-17%
Business support costs	16%	3%	23%	16%	-8%	10%	2064	2761	2294	11%	-17%
Total	26%	16%	6%	19%	13%	20%	18293	25243	20937	14%	-17%

The above table shows that the DD proposals will increase overall baseline totex by 14% or £2.5 billion compared to ED1. We would highlight the following points.

- **Load-related expenditure** - as expected, the most substantial element of the increase (£1.4bn) is attributable to a 97% increase in load related capex (LRE). The most significant LRE increases are attributable to ENWL, NPg and SSEN.
- **Non-load related expenditure** increases by 11% or c£600m, with UKPN and SSEN showing the highest increases.
- **Non-operational capex** increases by 58% or c£450m, which may be attributable to increases in DSO and associated expenditure. SPEN show the largest increase of 131%.
- **Network operating costs** show a 17% or c£700m reduction overall.
- **Non-operational operating costs** also show a substantial increase, with c£900m of additional expenditure across business support and closely associated indirect categories.

Based on this comparison of companies with their current performance, we are concerned that the DD cost modelling and consequent proposals may not have fully addressed some of the inconsistencies and potential outliers demonstrated by the above comparison. To illustrate this, we have compared Ofgem's DD proposals for underlying totex (excluding LRE and uncertainty mechanisms) as shown below.

Table 7: Comparison of totex proposals excluding LRE

Totex excluding LRE				% change from ED1 to DD	% change from BP submission
	ED1 equivalent (£m)	ED2 submission (£m)	ED2 proposal (£m)		
ENWL	1232	1713	1389	13%	-19%
NPg	2163	2593	2143	-1%	-17%
WPD	4815	5961	4814	0%	-19%
UKPN	3734	4855	4312	15%	-11%
SPEN	2364	2963	2554	8%	-14%
SSEN	2552	3743	2900	14%	-23%
Total	16859	21828	18112	7%	-17%

We note that there is an overall increase in underlying expenditure of 7% or £1,253m from the equivalent ED1 run rate after catch-up and ongoing efficiency improvements are deducted but before RPE costs are added. The companies (WPD and NPg) that have been given relatively flat allowances are still effectively receiving an increase in real terms that offsets the efficiency deductions.

We would highlight two issues from this comparison:

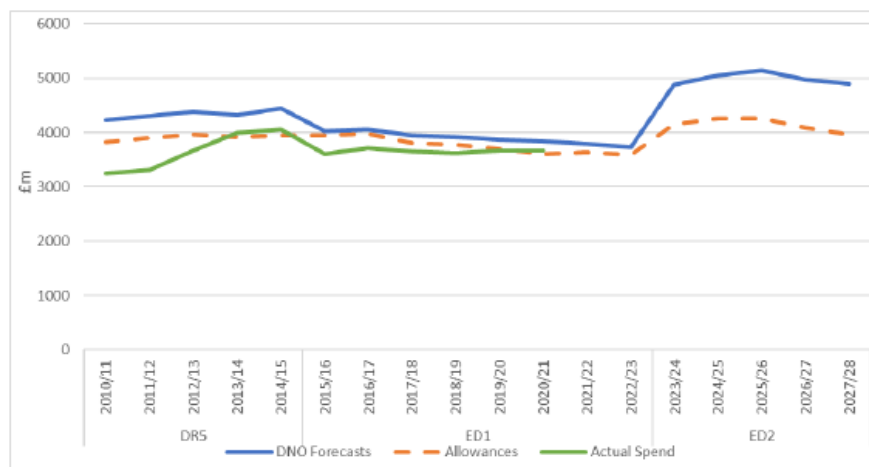
- First, the mainly stable underlying network characteristics of the DNOs should mean that these non-LRE costs may be expected to remain relatively stable between price controls. Potential increases of some £600m in DSO and digitalisation costs in ED2 should be offset by the proposed catch up efficiency savings (£300m) and the ongoing efficiency savings (£1299m).
- Second, it is unclear why the DD proposals should allocate significant increases to some DNOs while keeping others flat.

For example, if the run-rate of these non-LRE costs were to be kept flat across all DNOs, then this could potentially result in a further saving of some £1.2 billion from the position in Ofgem's DD proposals. This saving could benefit hard-pressed consumers without jeopardising Net Zero ambitions, or network reliability.

We also note that Ofgem has identified in the DD consultation that the step change in forecast expenditure (as illustrated by the following chart) has presented a challenge to their cost assessment.

Figure 8: Totex profile from DD document

Figure 16 Totex Forecasts, Allowances and Actuals from DPCR5 to RIIIO-ED2 (£m, 2020/21 prices)



Given this evidence of potentially disproportionate allowances across companies resulting from the current approach to totex assessment, we suggest that it may be appropriate for Ofgem to consider the introduction of a further adjustment mechanism to the allowances. These could take the form of:

- a cap for non-LRE expenditure such that these allowances would be reduced for companies that have above average increases
- for LRE (where NPg, ENWL, SSEN) have above-average increases, we suggest that these baseline allowances could be reduced to an average level, with the remainder being addressed through uncertainty mechanisms such that Net Zero ambitions are not impacted.

We have provided further comments on the specific consultation questions in the following sections.

Approach to cost assessment

Core-Q63. Do you agree with our proposed approach to pre-modelling normalisations and adjustments?

Core-Q64. Do you agree with our approach to totex benchmarking?

Ofgem has used a combination of aggregated (totex) and disaggregated (activity-level) benchmarking to assess DNO costs, supported by technical assessment where benchmarking is not suitable, such as where costs are company- or project-specific.

The results from three totex and one disaggregated cost models are combined to create a single view of modelled costs. Post modelling adjustments are then made to add a common demand profile and introduce efficiency adjustments.

To benchmark costs on a comparable basis, Ofgem first undertakes a normalisation process aimed at making any necessary adjustments to company submitted data to ensure they are consistent.

Challenge Group comments

Notwithstanding our earlier comments on the apparent inconsistencies observed with allowances compared with ED1 levels, we would make the following comments.

Normalisation and adjustments - we note the approach that Ofgem has taken to address regional and company specific factors, together with other adjustments prior to cost modelling. We agree with the proposed approaches.

Cost modelling and benchmarking - we agree that it is important that a consistent cost assessment approach should be used, building on experience from ED1. But it must address the significant increases from past performance in the company bids for ED2. Given the extent of the apparent inconsistencies between companies that we have highlighted in our earlier comparisons, we would question whether the modelling approach fully addresses these inconsistencies.

As mentioned earlier, Ofgem has identified in the DD consultation that the step change in forecast expenditure has presented a challenge to cost assessment. If the higher increases above BAU for ED2 by some companies are causing a modelling distortion then we suggest that the Ofgem analysis should correct for this, thereby ensuring fair, comparable totex profiles across companies and their customers.

Disaggregated benchmarking – we welcome that this analysis has been included in the assessment, allowing individual areas to be assessed in more detail using a variety of approaches. Again, we note that the ED1/ED2 time period under consideration includes the steep increases in some of these costs by some companies for ED2. It is unclear how this was taken into account in the assessment of benchmarks and efficient costs. For example, we noted in our February 2022 report that there was a broad range of expenditure plans by DNOs for digitalisation, IT and DSO activities.

Overall, we accept that there is a challenge to use benchmarking of widely differing and new costs to determine efficient expenditure levels. But, if the cost modelling approach has the effect of increasing allowances due to high bids in some cost categories, then this is unlikely to be the best value outcome. It will be important not to reward inefficiency, nor to penalise efficient proposals.

Load-related expenditure

Core-Q65. Do you agree with our proposed assessment approach for primary reinforcement?

Core-Q66. Do you agree with the application of a volume adjustment based on the industry average ratio of forecast capacity added relative to the forecast demand growth above firm capacity? If not, what do you consider to be a better approach to assessing the efficiency of a DNO's proposed workload for primary network reinforcement?

Core-Q67. Do you agree with our proposed assessment approach for secondary reinforcement?

Core-Q68. Do you agree with the level of disaggregation and period of data used to calculate the unit costs listed in the table above for transformer reinforcement, circuit reinforcement and proactive service reinforcement?

Core-Q69. Do you agree with our proposed assessment approach for fault level reinforcement?

Core-Q70. Do you agree with our proposed adjustments to account for outlier volumes data for ENWL and SSES?

Core-Q71. Do you agree with our proposed assessment approach for connections?

Core-Q72. Do you agree with our proposed assessment approach for NTTC expenditure?

Ofgem has undertaken analysis for each of the LRE activity levels. The activity categories considered are:

- primary reinforcement - costs and volumes are proposed based on median forecast unit costs and volumes are adjusted where higher than the industry upper quartile ratio
- secondary reinforcement - a disaggregated unit cost assessment with benchmarked volumes for transformer, circuit and proactive service reinforcement. Unit costs were disaggregated by asset category and volumes benchmarked to LCT additions
- fault level – industry median costs from ED1/ED2 (excluding ENWL). Volumes as submitted except SSES as an outlier
- connections – an industry median unit cost per connection type using ED1/ED2 data with MPANs connected as the cost driver. MPAN volumes as submitted by each DNO
- new transmission Capacity charges – qualitative assessment.

Ofgem notes that flexibility cost forecasts have been included as part of the primary and secondary reinforcement activities. Load indices are highlighted as a support tool and are proposed for use in assessing future re-opener submissions.

We agree that the above approach is an appropriate way to determine costs and volumes of load-related expenditure. We have compared the Ofgem DD proposal for load related capex with the ED1 5-year equivalent and the DNO group ED2 submissions in the table, below.

Table 8: Load-related capex

LRE

	ED1 equivalent (£m)	ED2 submission (£m)	ED2 proposal (£m)	% change from ED1 to DD	% change from BP submission
ENWL	74	302	252	243%	-17%
NPg	130	636	506	289%	-20%
WPD	474	946	766	62%	-19%
UKPN	343	607	541	58%	-11%
SPEN	230	434	374	63%	-14%
SSEN	186	490	386	108%	-21%
Total	1435	3415	2825	97%	-17%

The overall increase in LRE over ED1 is 97%, reflecting the significant increase expected in LCT technologies and associated network capacity. This forecast includes the demand driven adjustment, so we are concerned that some companies - for example, NPg and ENWL - appear to be outliers in their forecasts. SSEN are also higher than average. This would suggest that the demand-driven adjustment may need to be considered further for these companies. This is an area of considerable uncertainty, with uncertainty mechanisms expecting to play a major role as discussed earlier in our response.

Non-load related expenditure

Core-Q73. Do you agree with our proposed assessment approach on asset replacement?

Core-Q74. Do you agree with our assessment approach to refurbishment?

Core-Q75 - 90. Do you agree with our proposed assessment approach for all other NLRE costs?

We agree with the approach that Ofgem has taken for assessment of the following NLRE costs:

- Asset replacement – using an industry median unit cost per asset category based on ED1 and ED2 data, as well as expert review. A combination of age-based modelling, run-rate analysis and qualitative review to assess volumes
- Asset refurbishment - using an industry median unit cost per asset category based on ED1 and ED2 data. Volumes based on both quantitative and qualitative assessment
- Condition based civil works – median costs and benchmarked volumes
- Diversions – industry median costs and DNO submissions
- Rail Diversions - nil funding and re-opener
- IT&T – ratio benchmarking using MEAV as cost driver and based on ED1 and ED2 data
- Legal and safety – ratio benchmarking and qualitative assessments
- Overhead line clearance – ED1/ED2 median cost with engineering review for volumes
- Restoration – qualitative assessments
- QoS – excluded or reclassified
- Physical security – ENWL and SSEN submitted proposals for Control Centre funding under this category. These were qualitatively assessed with ENWL expenditure allowed and SSEN disallowed due to insufficient justification
- Flood mitigation – industry median cost from ED1/ED2 with engineering review for volumes
- Rising/lateral mains – DNO median cost from ED1/ED2 with customers as volume driver
- Worst-served customers – costs accepted as submitted
- Losses – ED2 expert median unit cost plus engineering review for volume adjustments
- Environmental reporting excluding PCBs – industry or DNO median costs for ED1/ED2
- PCBs – DNO median unit cost across ED1/ED2. Submitted volumes accepted.

We have compared the Ofgem DD proposal for non-load related capex with the ED1 5-year equivalent and the DNO group ED2 submissions in the table. below.

Table 9: Non-load related capex

NLRE					
	ED1 equivalent (£m)	ED2 submission (£m)	ED2 proposal (£m)	% change from ED1 to DD	% change from BP submission
ENWL	446	640	519	16%	-19%
NPg	807	927	767	-5%	-17%
WPD	1675	2082	1677	0%	-19%
UKPN	1007	1396	1239	23%	-11%
SPEN	892	1173	1007	13%	-14%
SSEN	802	1330	1010	26%	-24%
Total	5628	7548	6219	11%	-18%

This highlights that DD ED2 non-load related capex costs are 11% above the ED1 average. There are significant differences between company expenditure allowances for ED2, with SSEN and UKPN showing the highest increases.

We would anticipate that these expenditure profiles should be similar between ED1 and ED2, with the main cost driver, that of asset health remaining constant. All companies have reported that asset health targets should be met by the end of ED1, therefore a similar expenditure profile may be expected during ED2 for each DNO's asset base.

Non-operational capex

Core-Q91 - 3. Do you agree with our proposed assessment approach for Property, STEPm, IT&T, and Vehicles and Transport?

Non-Operational Capex includes four activities:

- Property
- Small Tools, Equipment, Plant and Machinery (STEPm)
- IT&T (see
- Technologies and Telecommunications (IT&T)
- Vehicles and Transport.

Ofgem has assessed these costs using ratio benchmarking with MEAV as the cost driver and an industry median benchmark ratio based on ED1 and ED2 data. We note that Ofgem assessed all IT&T costs together (Operational, Non-Operational and Business Support Information Costs), together with a qualitative review of the DNOs' EJPs and IT&T strategies. We agree that this an appropriate response.

We have compared the Ofgem DD proposal for non-operational capex with the ED1 5-year equivalent and the DNO group ED2 submissions in the table, below.

Table 10: Non-operational capex

Non-operational capex					
	ED1 equivalent (£m)	ED2 submission (£m)	ED2 proposal (£m)	% change from ED1 to DD	% change from submission
ENWL	58	93	76	31%	-18%
NPg	96	155	128	34%	-17%
WPD	257	517	418	63%	-19%
UKPN	185	342	305	65%	-11%
SPEN	62	164	142	131%	-13%
SSEN	130	221	173	33%	-22%
Total	786	1492	1242	58%	-17%

This highlights that DD ED2 non-operational capex costs are 58% above the ED1 average. This is likely to be mainly attributable to additional DSO and digitalisation expenditure required for ED2.

We would highlight that there are significant variations between DNO groups in their expenditure increases in this area, raising concerns about their respective effectiveness and efficiency of delivery. It will be important for sufficient IT&T investment to be included in allowances to ensure that DSO capabilities and flexibility benefits are realised, but we suggest that additional scrutiny is given to potential cost outliers in this area.

High value projects (HVP)

Core-Q94. Do you agree with our proposed assessment approach for HVPs?

Core-Q95. Do you see any merit in setting a HVP threshold for RIIO-ED2, and if so, should it be based on the RIIO-ED1 threshold?

We agree that a HVP uncertainty mechanism should be included for non-load related projects, and agree that the £25m threshold appears appropriate.

We note that three HVPs - for ENWL (£18m), WPD (£25m), and SSEN (£67m) - have been included in the DD modelled costs, totalling £110m. We agree these projects should be assessed separately before potential inclusion in the ED2 final determinations.

Network operating costs

Core-Q96 – 102. Do you agree with our proposed assessment approach for Network Operating Costs?

Network operating costs (NOCs) are the day-to-day costs incurred by DNOs as part of the work required to maintain and operate the distribution networks. The Ofgem modelling proposals are:

- Faults and Occurrences Not Incentivised (ONIs) – used regression analysis pooling Faults and ONIs costs using DPCR5, ED1 and ED2 data, and Faults volumes and ONIs volumes as independent variables.
- Severe Weather 1-in-20 events - this activity was excluded from cost assessment. A UIOLI mechanism with a zero starting allowance is proposed.
- Tree Cutting – used industry median unit costs based on ED1 and ED2 data. Volumes derived from run rates.

- Inspections and Repairs & Maintenance - used MEAV ratio benchmarking, with the industry median as a benchmark and based on ED1 and ED2 data.
- NOCs Other – For dismantlement, Ofgem used MEAV ratio benchmarking based on ED1 and ED2 data. For remote generation Opex, Ofgem used submitted costs. For substation electricity, Ofgem used DNOs' median unit costs based on ED1 and ED2 data.
- Smart Metering Rollout - Ofgem proposes to remove the volume driver and provide an ex ante allowance, set using an industry median unit cost based on RIIO-ED2 data.

These approaches appear appropriate and use available evidence. We agree with the approach that Ofgem has adopted for each of these network operating cost categories.

We note that the DD modelled costs resulted in an overall 17% reduction from company aggregate submissions. We have compared the Ofgem DD proposal for network operating costs with the ED1 5-year equivalent and the DNO group ED2 submissions in the table below. This highlights that efficient ED2 network operating costs appear to be 17% below the ED1 average.

Table 11: Network Operating Costs

Network operating costs					
	ED1 equivalent (£m)	ED2 submission (£m)	ED2 proposal (£m)	% change from ED1 to DD	% change from BP submission
ENWL	289	320	259	-10%	-19%
NPg	596	587	486	-18%	-17%
WPD	1206	1103	891	-26%	-19%
UKPN	1071	997	885	-17%	-11%
SPEN	493	531	459	-7%	-14%
SSEN	609	716	561	-8%	-22%
Total	4262	4254	3541	-17%	-17%

Closely associated indirects and business support

Core-Q102 - 3. Do you agree with our approach to assessing CAI and Business Support costs?

Closely associated indirects – these include the back-office functions directly involved in the construction and operation of network assets, including project management and network design. We note that Ofgem assessed CAI costs through regression analysis using MEAV as a driver to reflect scale of the network asset base and used ED1 and ED2 data. The analysis was performed at a licenced company level. The DD modelled costs resulted in an overall 17% reduction from company aggregate submissions.

We have compared the Ofgem DD proposal for CAI with the ED1 5-year equivalent and the DNO group ED2 submissions in the table below.

Table 12: Closely associated indirects

Closely associated indirects				% change from ED1 to DD	% change from BP submission
	ED1 equivalent (£m)	ED2 submission (£m)	ED2 proposal (£m)		
ENWL	261	404	327	26%	-19%
NPg	423	621	512	21%	-18%
WPD	1184	1506	1219	3%	-19%
UKPN	1026	1535	1363	33%	-11%
SPEN	569	726	627	10%	-14%
SSEN	658	981	768	17%	-22%
Total	4120	5773	4816	17%	-17%

Overall, while the DD proposal shows a 17% cut from company submissions, this still reflects a 17% increase from ED1 run rates. While some increase in this area may be expected due to additional support work for load-related expenditure, efficiency improvements may also be expected.

We note that there appears to be a significant difference between the individual DNO group allowances, with UKPN and ENWL allowances at DD increasing much more than WPD for example.

Business support costs

Business support costs include corporate support functions, IT & Telecoms, and property management costs. We note that Ofgem also assessed business support costs through regression analysis using MEAV as a driver to reflect scale of the network asset base and used ED1 and ED2 data. The DD modelled costs also resulted in an overall 17% reduction from DNO aggregate submissions.

We have compared the Ofgem DD proposal for business support with the ED1 5-year equivalent and the company ED2 submissions in the table below.

Table 13: Business support costs

Business support				% change from ED1 to DD	% change from BP submission
	ED1 equivalent (£m)	ED2 submission (£m)	ED2 proposal (£m)		
ENWL	179	256	208	16%	-19%
NPg	243	303	250	3%	-17%
WPD	494	753	609	23%	-19%
UKPN	447	585	520	16%	-11%
SPEN	349	369	319	-8%	-14%
SSEN	354	495	388	10%	-22%
Total	2064	2761	2294	11%	-17%

Overall, while the DD proposal shows a 17% cut from company submissions, this still reflects a 11% increase from ED1 run rates. We note that, in contrast to CAI, the DD proposals give WPD the largest increase from ED1, with the SPEN allowance showing a reduction from ED1.

CAI and business support – Challenge Group comments

Overall, we agree with the modelling approach used by Ofgem for CAI and business support costs, using regression analysis over ED1 and ED2 and for DNO data only and using MEAV as a driver. We consider that there is evidence to suggest that further reductions could be made, including:

- while the Ofgem modelling reduces these costs by 17% overall, both cost categories show significant increases from ED1, with significant differences across DNO groups. Should these differences be addressed?
- while using MEAV as a driver appears the most appropriate in the circumstances, business support costs may not be expected to increase at the same rate as MEAV as economies of scale are gained. It may be appropriate to apply a lower growth driver to these costs.
- the recent acquisition of WPD by National Grid will likely result in cost savings in business support – should these be reflected in the allowance for the DNO group?

Street works

Core-Q104. Do you agree with our approach to assessing street works costs?

Street works costs result from complying with traffic management legislation, particularly permit and lane rental costs. Ofgem proposes to use each DNO's recent street works costs to model its future spend, with a ratchet mechanism that selects the lower of DNO submitted and modelled costs for future years. We agree with this approach.

Post modelling adjustments

Core-Q105. Do you agree with our proposal to carry out a demand driven post-modelling adjustment?

Core-Q106. Do you agree with our proposal to not carry out any Quality of Service based adjustments?

Core-Q107. Do you agree with our approach to combining our totex and disaggregated benchmarking models?

Core-Q108. Do you agree with our approach to setting and applying the efficiency challenge using a glide path between the 75th and 85th percentile over a 3-year period?

Core-Q109. Do you agree with our proposed RPEs allowances? Please specifically consider our proposed notional cost structure, assessment of materiality, and choice of indices in your answer.

Core-Q110. Do you agree with our proposed approach to setting the ongoing efficiency challenge and the level of challenge applied?

Core-Q111. Do you agree with our proposed disaggregation methodology?

Demand driven adjustment

We agree that a demand driven adjustment is important to bring all the DNO workload activities onto a common basis so that cost and volume benchmarking can be performed. Given uncertainty about the timing of LCT take-up and the widely varying views of the DNOs, we agree that it is more appropriate to have a lower baseline that can flex up. We agree that the simple application of the System Transformation demand profile is appropriate. In our earlier comments, we note that some of the DNOs have been given higher LRE increases from ED1, which appears unjustified and we suggest this is examined further.

We have provided further comment on this issue in our response on load-related uncertainty mechanisms. We also suggest that the lower proposed baseline should be able to flex down as well given uncertainties about underlying demand arising from the energy crisis and the growth of flexibility.

Quality of service adjustment

Ofgem does not propose to provide specific allowances for Quality of Service. We agree with this approach and that this issue is addressed within the existing totex allowances and reliability performance incentives.

Combining models and efficiency challenge

We are unable to comment on whether the proposed approach to combine models is appropriate. We agree that an efficiency challenge should be included by using a glide path between the 75th and 85th percentile over a 3-year period.

Real price effects and ongoing efficiency

Real Price effects - Ofgem proposes to include adjustments for RPEs in allowances for all network companies based on ex-ante forecasts of input price indices. Ex-post true-up adjustments will be applied annually. Ofgem's proposed ED2 RPE forecasts are set out below.

Table 14: ED2 RFE forecasts

Category	Weighting	2023/24	2024/25	2025/2026	2026/27	2027/28
Labour	63%	0.4%	1.0%	1.0%	1.0%	1.0%
Materials	25%	1.6%	1.6%	1.6%	1.6%	1.6%
Totex ²⁴⁷	-	0.7%	1.0%	1.0%	1.0%	1.0%

Ongoing efficiency – in our February 2022 report we raised concern about the limited ambition for ongoing efficiency assumptions by many DNOs, with submitted forecasts ranging between 0.5% - 1%. We agree with Ofgem's analysis that a 1% ongoing efficiency challenge represents a relatively stable outlook for the frontier efficiency achievements possible in ED2.

We agree that the context of transformational change in ED2, with additional investment in areas such as network visibility, DSO, and digitalisation, together with innovation, should drive higher productivity improvements across the sector. It will be important that hard-pressed customers can benefit from these additional productivity improvements. As such, we consider that Ofgem's proposal for a 1.2% ongoing efficiency challenge is appropriate, representing a more stretching outlook for the frontier efficiency achievements and taking account of the expected digitalisation and DSO benefits.

Disaggregation of allowances

In order to compare allowed costs against submitted costs, Ofgem has disaggregated these costs by DNO activity cost submissions. We agree this is an appropriate approach which should reflect the operational approach planned by DNOs.

Increasing competition

Q9. Do you agree with our proposed position on early and late competition?

Competition in infrastructure provision should drive significant benefits for consumers. Once in place for transmission, we agree that the early or late competition model should be applied to large projects in the electricity distribution sector. We note that no projects are being considered suitable for ED2 but Ofgem proposes to consider new projects that may emerge through re-openers.

We agree with Ofgem's observation that it is important that network companies should develop projects in such a way that avoids creating unnecessary barriers to delivery through a competition model. We are concerned that DNOs may seek to split up capital projects inefficiently to avoid their meeting the £50m or £100m criteria for competition.

While we agree with the decision not to proceed with competition at the start of ED2, we suggest that Ofgem considers how such potential for gaming may be addressed through compliance and enforcement.

6. Uncertainty mechanisms

Our comments on common and bespoke uncertainty mechanisms proposed in the Draft Determinations are included below.

Common uncertainty mechanisms

We support the approach that Ofgem has taken in using common uncertainty mechanism, including the addition of common uncertainty mechanism for load-related expenditure and PCBs. Our comments on load-related uncertainty mechanisms are provided in the 'Networks for Net Zero' chapter of our response.

We have provided our responses to the remaining specific questions on new common uncertainty mechanisms below.

Electric vehicle provider of last resort (EV PoLR)

Q1. Do you agree with our proposal to introduce a new funding mechanism for PoLR activities?

Q2. What are your views on our two proposed options, and do you agree with our preferred option of a DRS?

Ofgem notes that Standard Licence Condition 31F (SLC 31F) permits DNOs to act as the Provider of Last Resort (PoLR) and operate EV charge points, 'where the Authority is satisfied that no person other than the licensee is able to own, develop, manage or operate an Electric Vehicle (EV) charging point or could not do so at a reasonable cost and in a timely manner'.

Ofgem proposes to provide a funding mechanism for all DNOs, to recover costs associated with the development, management or operation of necessary EV charge points where the DNO is providing these in the case of wider market failure.

We note that this has not yet been required but we agree it is important that any charge points falling in this category should be adequately funded to enable the transition to a decarbonised transport system. We support the introduction of this funding mechanism by means of a Directly Remunerated Service. This means that these costs can be directly monitored and do not become part of the Regulated Asset Base. Charge point provision is a market-based activity and we agree that these assets should not remain within DNO ownership for extended periods.

High value projects re-opener

Q4. Do you agree with our proposal to maintain the RIIO-ED1 High Value Project mechanism and focus it on non-load related HVPs in RIIO-ED2?

Ofgem proposes to maintain a HVP for non-load related projects. This would have a value in excess of £25m and the re-opener window would be in January 2026. LRE HVPs would be addressed separately through the LRE re-opener.

We agree with this approach.

Access and Forward-looking Charges Significant Code Review

Q11. Do you agree with our proposal to not introduce a specific uncertainty mechanism to manage the impact of the Access SCR (and address it through the LRE mechanisms instead)? Please explain why.

We note that the impact of the SCR may range between some £30m-£300m of LRE per DNO, but DNOs have taken different approaches to assessing the impact. We agree that an additional uncertainty mechanism will be difficult to define and that this change should be managed through the proposed LRE uncertainty mechanism.

Bespoke uncertainty mechanisms

In our February report we suggested that most bespoke re-openers proposed by DNOs should be considered as business-as-usual activities included within the price control. The Ofgem proposals show that DNOs currently enjoy the benefit of more than 30 common uncertainty mechanisms, as well as increased expenditure allowances over current levels.

We welcome the fact that Ofgem has also adopted this approach and rejected most of the DNO proposed bespoke uncertainty mechanisms. We agree that it makes sense for the PCB uncertainty mechanism to be included as a common mechanism.

Bespoke re-openers are proposed for major projects at Moorside (ENWL), Shetland and Hebrides & Orkney (both SSEN). We agree that this is appropriate.

7. Finance

Ofgem's Proposals

The proposals set out in the DD Finance Annex closely mirrored those in the SSMD. They provide for:

- Full indexation of the Cost of Debt allowance based on a 17-year trailing average of the iBoxx GBP Utilities 10yr+ index with a 25 bps allowance for additional costs of borrowing and a 6 bps 'infrequent issuer premium' for three licensees
- An indexed Cost of Equity allowance of 4.75% with no outperformance allowance
- Detailed provisions in relation to financeability, depreciation, capitalisation and financial governance which are much in line with the SSMD
- A recognition that the impact of potentially persistent levels of inflation higher than foreseen at the time when the SSMD was drawn up needs to be carefully assessed.

Challenge Group Comments

In broad terms, the Challenge Group is supportive of the financing aspects of the DD which, like the SSMD on which the DD is closely based, it regards as well supported by economic and financial evidence and sound analysis of outcomes in ED1 and both the energy and wider utilities markets. Our detailed answers to questions are set out below but we highlight two important areas where we consider that Ofgem's approach could have been more favourable to consumers and one where we believe very careful analysis is needed.

- Ofgem's own analysis, as set out in the DD, particularly when taken together with cross-checking based on recent market transactions, in our view supports a Cost of Equity below 4.75%. We consider that, taken as a whole, the price control provides DNOs with a great deal of protection from risk combined with significant upside opportunity. The DNOs' Cost of Capital is an important component of the energy cost to consumers and, particularly in the current economic climate, we think that Ofgem should have regard to its own analysis and consider a Cost of Equity allowance below 4.75%.
- We understand the rationale for the 'infrequent issuer premium' on the Cost of Debt allowance and note that it is not large and has been given to only three licensees. We have however never been supportive of this premium which we do not regard as necessary, especially for licensees which are part of a large group.
- We think that Ofgem should give careful consideration to the potential for the companies to earn windfall gains as a result of high rates of inflation. It is important that measures are not put in place in haste which could have unintended consequences. But, in our view, it is equally important that economic circumstances do not afford opportunities for gain which are particularly undesirable at a time of financial stringency and can also have the effect of undermining the incentive regime (by permitting acceptable returns without the need to maximise incentive payments).

Consultation question on allowed return on debt

FQ1. Do you agree with our approach to estimating efficient debt costs and setting allowances for debt costs?

We are supportive of Ofgem's general approach to setting cost of debt allowances, including the proposal to index debt costs and the construction and calibration of the index proposed. We consider the 25 bps 'Additional costs of borrowing' allowance to be unnecessarily generous. We understand Ofgem's rationale (the setting of allowances based on the Notional Company) for an 'infrequent issuer premium' and we note that the premium allowed is small (6 bps) and is to apply to only three licensees. However, all of these licensees are part of large groups and we have commented before and reiterate that, in our view, no premium (however small and however narrowly applied) is necessary or in the interests of consumers. We urge Ofgem not to extend the arrangement, as potentially foreseen in paragraph 2.33. As a separate point, we are supportive of the approach to ENWL's proposals.

Step 1 - Consultation question on risk-free rate and equity indexation

FQ2. Do you have any views on the model to implement equity indexation that is published alongside this document, (the 'WACC Allowance Model - RIIO-ED2 30th April 2022 update Alternative Wedge')?

We remain supportive of the principle of equity indexation, as we were in relation to the GD & T determination – and agree with the arrangements proposed.

FQ3. In light of the upcoming change to the definition of RPI in 2030, should the RPI-CPIH inflation wedge be based on: a) a single year (as shown in the WACC allowance model when: cell D2 is "year 5 forecast" and cell B5 is "01/04/2022"); or b) should it be based on 20 years of inflation forecasts (as shown in the WACC allowance model when: cell D2 is "20 year geometric" and cell B5 is "01/04/2031")?

No strong view but there appears to be some merit intellectually and in practice in (b): we can see benefit in minimising the RPI-CPIH 'wedge'.

Step 1 - Consultation questions on TMR

FQ4. Is there evidence that suggests we should change our approach to TMR for RIIO-ED2?

FQ5. Can stakeholders confirm their view on the trade-off between: the objectivity of using outturn averages (even though the results may be materially higher or lower in future price controls than current TMR expectations); versus the benefits of putting more weight on current expectations (noting the evidence from cross-checks and the associated risk of subjectivity)?

FQ6. Do stakeholders agree with our proposal to apply the same TMR for RIIO-ED2 (a mid-point of 6.5% CPIH) as we did for RIIO-GD&T2?

In the light of the anticipated deterioration in the economy, it will be necessary to take account of market sentiment which may prove to be quite fast evolving in the months running up to the FD but we can see no need for a change approach to the setting of the TMR: we do not consider there to be a basis for needing to distinguish between sub-sectors and we do not think the risk profile of ED2 is materially different from that in ED1 and that many of the risks are, in any case, mirrored by significantly increased opportunity for outperformance.

We accept that a higher potential level of inflation might increase risks for the DNOs but note that it also offers significant potential benefits and that the very high proportion of expenditure which is subject to

uncertainty mechanisms of one sort or another places significant downward pressure on their risk profile for ED2. As of today (and taking into account Ofgem's own cross-checks), we take the view that the highest acceptable level for the mid-point TMR for ED2 is 6.5% CPIH but that a good case can be made for a lower figure.

Step 1 - Consultation questions on beta

FQ7. Do you believe that DNOs have a higher or lower level of systematic risk than the GD&T companies during their respective RIIO-2 periods?

FQ8. What are your views on the relative risk comparison shown in Table 10?

FQ9. Do you have any evidence that suggests the beta for GD&T companies has materially changed since RIIO-GD&T2 Final Determinations in December 2020?

We have consistently argued both in the context of ED2 and the settlement for GD & T that, overall, the systemic risk profile of the UK energy subsectors is very similar and, indeed, also very similar to that of the UK water sector. We agree with the proposition that, overall, National Grid plc is a good proxy for systematic risk in the UK electricity distribution sector. There are, of course, differences both up and down – most of which are well set out in Table 10 – but we continue to regard the overall net position between subsectors as very similar.

We consider not only that there are important similarities between subsectors (and different regulated utilities) but also, in recent years, over time: we can see no reason for Ofgem to take a view of the appropriate beta different to that which it expressed in the FDs for the GD & T subsectors in December 2020.

Step 2 - implied cost of equity consultation questions

FQ10. Do you agree with our interpretation of the cross-check evidence?

FQ11. Do you agree with our updated MAR and OFTO cross-check techniques, in terms of drawing better inferences for RIIO-ED2?

FQ12. Do you agree with the cross-checks we have used and are there other cross-checks we should consider?

FQ13. Do you consider we should put greater weight on cross-checks or reconsider our CAPM parameters in light of the adjusted cross-check results?

We consider evaluation of actual recent transactions, both related to land-based networks of various kinds and to OFTOs, to constitute important, and necessary, cross-checks to Ofgem's CAPM-based analysis. We agree with Ofgem's interpretation of the evidence, as set out in paragraph 3.65 of the DD and also with its conclusion that the evidence points to a lower Cost of Equity allowance than 4.75%. There are differences between the OFTO regime and the risk profile of the DNOs. But we agree with Ofgem's conclusion that, although operational/asset risk may be lower, financial risk in the OFTOs is probably higher (because of the higher level of gearing) so that the overall systemic risk profile between the two may be not dissimilar. This would, of course, in turn support a Cost of Equity allowance lower than 4.75%.

We note, in particular, that overwhelmingly the most significant risk faced by the DNOs is arguably best characterised as ‘regulatory’ and that the arrangements proposed for ED2 (wide ranging UMs, RoRE range, inflation pass throughs etc) all serve to reduce that risk.

In a potentially fast-changing financial market, the position will need to be reviewed at the time of the FD but our current view is that Ofgem will need to reconsider the appropriate response to its own convincing arguments that the cost of equity for the DNO sub-sector is lower than 4.75%. We consider it very important that the FD reflects the fact that, although the overall settlement proposed (a wider RoRE range, higher totex incentives and almost certainly a considerably greater requirement for investment) exposes the companies to some increased risk, it also provides them with very substantial potential opportunities.

At a time of extreme financial stringency for consumers, we can see no reason not to set the Cost of Equity allowance nearer to the level to be derived from analysis of recent transactions.

Step 3 - allowed return on equity consultation questions

FQ14. Do you agree that we should not adjust for expected outperformance when setting baseline allowed returns on equity?

FQ15. Do you believe there is new evidence which would support an adjustment downwards (eg expected outperformance) or upwards (eg aiming up) that we have not yet considered?

We have expressed the view in the context of both ED2 and GD & T2 that there is compelling evidence of systemic outperformance of price reviews, probably based primarily on information asymmetry. We consider it important for consumers that measures are put in place to limit the extent to which companies are able to benefit from such asymmetry and, against that background, have always been supportive of the concept of the outperformance ‘wedge’ on the basis that it was the methodology for dealing with a difficult problem which had the fewest disadvantages. We accept that the CMA has taken a different view and that, against that background, it is better that Ofgem should find a different method of dealing with the problem.

In particular, it is important that the Cost of Equity allowance is not set too high. We do not consider that there is any compelling argument, either new or otherwise, for ‘aiming up’ and that there may be reasons, as set out in paragraph 3.100, why aiming down would be appropriate. At the least, we consider that the indexation proposals and the very wide scope of the proposed uncertainty mechanisms offset any historic arguments for aiming up, and we consider there to be a number of arguments, at a time of great pressure on consumer prices for energy, for an element of aiming down. This could produce a Cost of Equity allowance which reflects the view expressed above viz. that the mid-point of the CAPM derived rate (4.75%) is unnecessarily high for the Cost of Equity allowance for ED2.

Inflation and WACC consultation questions

FQ16. Do you think we should adjust our approach to allowed returns (noting our approach to expected inflation for WACC and outturn inflation for RAV as described above) so that outturn inflation does not permit the notional company to generate real equity returns that are materially higher or lower than our cost of equity allowance? What would be the consequences to consumers and DNOs of doing so?

FQ17. If you believe we should make such an adjustment, what is the best method for making it?

FQ18. If you don't believe we should make such an adjustment, how should we ensure that the fairness of the price control is maintained to prevent ex post returns from deviating from ex ante expectations for both consumers and investors?

At a time when consumers are suffering from inflation in the economy generally and in the context of energy costs in particular, we think it very important that DNOs are not able to benefit from windfall gains resulting from higher than forecast inflation. If high rates of inflation persist, DNOs have the potential to make very substantial windfall gains as a result of a high rate of inflation being applied to RAV, much of which will be funded by historic debt incurred at a nominal interest rate which reflects the interest rate/inflation environment at the time when it was incurred. (There is an obvious parallel with the high returns to be earned from the holding of index-linked bonds over a period of higher than anticipated inflation).

Apart from the importance of protecting consumers from the impact of such windfall gains and the parallel importance of avoiding the associated reputational damage (to Ofgem as well as to the DNOs), we regard it as essential that the price control's incentive regime is not undermined by the companies having an ability to make returns satisfactory for their shareholders without needing to maximise the benefits to be derived from incentive mechanisms. We accept that some of the potential mitigations to the problem of high inflation could have unanticipated consequences and/or perceived/potential consequences which in turn could result in upward pressure on the Cost of Equity allowance which (see above) we regard as already higher than in the best interests of consumers.

We are therefore not urging precipitate action but we do consider it important that Ofgem give careful consideration ahead of the FD to the most effective way to tackle the issue, including quantification of its impact on consumers under different scenarios. This is an emerging problem and its extent, both in terms of the rates of inflation which are anticipated and the likely duration of a high inflation environment, is still very unclear. But, as of today, we regard it as one of the key potential risks of the ED2 price control. It needs to be given thorough review and analysis over the coming months.

Consultation questions on financeability

FQ19. Do you agree with our approach to assessing financeability?

FQ20. Do you have any evidence that would enable us to improve our calibration of stress test scenarios?

FQ21. Do you agree with the requirement to provide the Financial Resilience Report within 60 days?

We have always been supportive of Ofgem's use of the Notional Company as the basis for assessing financeability and we also agree with the CMA's comment in its Final Determinations on the GD & T appeals that Ofgem's financeability duty does not require it to ensure that, under all circumstances, all DNOs can recover all the costs which they have incurred.

We made clear in our comments on DNOs' business plans that we considered all of those plans to be financeable on the basis of the proposed Cost of Capital allowances. We consider that assessment to be borne out by the data set out in Table 20 of the Finance Annex of the DD. We also expressed the view that we regarded a target rating of BBB+/Baa1 to be at the upper end of the acceptable range and were clear that a higher target was not, in our view, in the interests of consumers.

Despite the changes in the economic climate which have occurred since January, we see no reason to alter our assessment either of the financeability of all the DNOs' business plans or of the strong

undesirability of targeting a rating above BBB+/Baa1. We are also supportive of Ofgem's concern about excessive focus on individual credit metrics (particularly AICR and PMICR) and of the need for 'in the round' assessment of financeability. In the case of almost all DNOs, we were unimpressed by the approach to measures which they could take to address financeability concerns: we made clear that we considered that their rejection of most of the measures available to them to improve financeability (as proposed by Ofgem in its SSMD and set out in paragraph 5.26 of the DD) was unhelpful. We have not changed that view.

We regard Ofgem's stress testing as soundly based but note that it may have to be reviewed at the FD stage if major changes in market conditions are forecast at that time.

We regard the requirement to provide a Financial Resilience Report within 60 days of a 'triggering event' as sensible and reasonable.

Consultation questions on corporation tax

FQ22. Do you agree with our proposals to make allocation and allowance rates variable values in the RIIO-ED2 PCFM?

FQ23. Do you agree with the proposed additional protections? In particular:

FQ24. Do you have any views on a materiality threshold for the tax reconciliation?

FQ25. Do you think that the "dead band" used in RIIO-ED1 is an appropriate threshold to use? If not, what would be a more appropriate alternative?

FQ26. Do you have any views on our proposals relating to the Tax Trigger and Tax Clawback mechanisms? In particular, do you have any views on a proposed "glide path" for the notional gearing levels used in the tax clawback calculation?

We regard all of the proposals in relation to tax as practicable and in the interests of consumers.

Consultation question on Return Adjustment Mechanisms

FQ27. Do you agree with our proposals for the RAM thresholds and adjustment rates?

We agree with Ofgem's description of the RAM as a 'failsafe mechanism' and its analysis that it is most unlikely to be triggered at even the 3% level, either up or down. However, we regard it as a useful safeguard and are supportive of the 3%/4% trigger levels and the sharing percentage proposed at each level. We consider that part of arrangements to deal with windfall gains from higher than forecast levels of inflation might usefully be their inclusion in the RAM calculation.

Consultation questions on indexation, depreciation and capitalisation rates

FQ28. What are your views on the technical implementation of the switch to CPIH as set out in the attached PCFM?

FQ29. Do you agree with our proposal to set depreciation policy on RAV additions in the RIIO-ED2 period to 45-years straight line, based on the average economic life of the assets?

FQ30. Do you agree with our proposal that we should set different capitalisation rates for ex ante allowances and re-openers and volume drivers?

FQ31. Do you have any evidence that would enable us to improve our estimates of regulatory capitalisation rates?

We agree with Ofgem's proposals in relation to both depreciation periods and capitalisation rates for the Notional Company but with the proviso that we consider that the rejection of the concept of making minor changes to either or both to aid financeability on the part of almost all companies in the context of the Actual Company to be unhelpful.

Consultation question on RAV opening balances

FQ32. Do you have any views on the use of forecast RAV opening balances for the start of RIIO-ED2, which will be trued-up following RIIO-ED1 closeout?

No strong views but the proposals appear appropriate.

Consultation question on transparency through RIIO-ED2 reporting

FQ33. Do you agree that additional corporate governance reporting described (including on executive director remuneration and dividend policies), will help to improve the legitimacy and transparency of a company's performance under the price control? If not, please outline your views in relation to the rationale provided for these additional requirements, including consumer protection.

We regard the proposals as highly desirable additions to the regulatory regime.

Questions on consolidated reporting and calculation, and self-publication of allowed revenue

FQ34. What are your views on the proposed consolidation of the revenue RRP and PCFM, or applying a fully dynamic concept of allowed revenue?

FQ35. What are your views on allowing licensees to self-publish the PCFM with their charging statements, rather than relying on an Ofgem publication or direction to determine allowed revenue?

We are in agreement with the proposal to consolidate all revenue into the PCFM. We accept that there are good practical reasons for the proposal to allow licensees to self-publish their PCFM with their charging statements but note that this will need to be supported by arrangements for detailed monitoring by Ofgem.

Questions on best vs reasonable endeavours in charge setting

FQ36. What are your views on having a best endeavours obligation for charge setting: 'The licensee must, when setting Network Charges, use its best endeavours to ensure that Recovered Revenue equals Allowed Revenue'?

We consider it fundamental that Recovered Revenue should equal Allowed Revenue and that the regulatory arrangements must be such as to ensure that this is the case. The implications of 'best endeavours' can give rise to legal issues and, if this is perceived to be a problem, 'reasonable best endeavours' may be appropriate. We do not regard 'reasonable endeavours' as sufficient and we agree with Ofgem that there is no basis for arguing that the DNO PC settlement should differ from that relating to GD & T in this respect.

Consultation questions on the appropriate time value of money

FQ37. What are your views on applying a single time value of money to all prior year adjustments, based on nominal WACC?

As a generality, it is obviously in the interests of consumers to use the lowest acceptable rate for adjustments of this type. Short-term interest rates will, by definition, be lower than the WACC but we can see sound arguments in favour of the latter and, as part of an overall robust settlement, would not be critical of it.

Question on forecasting

FQ38. What are your views on our proposed approach to using forecasts within RIIO-ED2?

FQ39. What are your views on the proposed charging penalty mechanism?

FQ40. What are your views on the proposed revenue forecasting penalty mechanism?

We are generally supportive of the proposals in relation to forecasting but note that it is important that true ups and dead bands are minimised so as to facilitate the calculation of tariffs by suppliers and hence minimise the extent to which they incorporate risk premia.

Consultation question on incentive lags, rates, caps and collars

FQ41. What are your views on removing lags from incentives?

FQ42. What is your view on using RoRE as a general baseline for describing ODI caps, rather than base revenue?

FQ43. What is your view on fixing the potential £m 20/21 value of incentives using one number for all years, based on a forecast of RIIO-ED2 at Final Determinations (an approach similar to RIIO-ED1)?

FQ44. What is your view on the method of calibrating incentive caps in RoRE terms, or the overall proposed incentive caps?

We are concerned that the removal of lags, which we accept has some merit in principle, will make it more difficult for suppliers to forecast tariffs. We accept that the risk is mitigated by the proposals in relation to forecasting errors but note the importance to the consumer of minimising the extent to which suppliers are exposed to risk for which they apply a premium. In other respects, we are supportive of the proposals relating to incentives.

Consultation question on bad debts

FQ45. What are your views on our proposal to remove the Bad Debt terms from the pass-through licence condition?

We support the greater clarity of the proposed change.

Consultation question on revenue profiling

FQ46. Should Ofgem allow proposals to re-allocate or re-profile revenue throughout the RIIO-ED2 period and what profiles could be considered in the customers' interest?

We consider it may be helpful to revisit this subject in the light of the current inflationary pressures in the economy but there are many reasons why as steady a profile as possible can be considered in consumers' interests.