



Appendix B – Detailed Consultation Response

Part 1: Drivers for change, ED3 objectives and consumer outcomes

1. Do you agree with our characterisation of the wider context for ED3? Are there any other areas of context that you consider material for ED3?

We broadly agree with Ofgem’s characterisation of the wider context for RIIO-ED3. Whilst we only have one full year of data from RIIO-ED2, the UK is at a critical juncture in its transition to net zero, and DNOs are key technical enablers of both the Clean Power by 2030 target, and the 2045 and 2050 net zero targets.

In addition, Distribution networks are also central to the wider mission for economic growth. The transition to a green economy presents a massive growth opportunity for the UK and this includes the projected growth of DNOs. For example, we already employ over 4,000 employees in our two operating regions and have plans to provide 850 jobs by 2028. Delivering our future plans will create green jobs for generations of young people while supporting a just transition by providing opportunities for workers to retrain and upskill as we move away from traditional industries like oil and gas. Ofgem have a duty to consider how regulatory decisions enable sustainable economic growth. DNOs provide critical national infrastructure that is central to the economy, and our plans to increase investment represent an important economic growth opportunity. These are both material factors for RIIO-ED3.

Drivers for Change:

- **Demand and decentralised energy:** due to accelerating peak demand and greater decentralisation, the distribution system will experience growing stress in the ED3 period. The *Clean Power 2030* report estimates that around 30% of GB’s 2030 clean power supply will come from onshore wind and solar, with around 30% of onshore wind and 90% on solar being connected directly to Distribution networks by 2030.¹
- **Transport and heat:** while the exact pace of transition remains uncertain, a societal shift towards electrification of heat and transport is underway – both will be important to achieving net zero goals. Our Distribution Future Energy Scenarios (DFES) projections suggest that we may have as many as 4.2 million battery electric vehicles and 1.5 million domestic heat pumps will be connected to our networks 2035.² This will be a significant driver of increased demand on our networks in ED3.
- **Strategic planning:** we agree on the importance of a strategically planned energy system at ED3. The introduction of RESP, CSNP and SSEP is a significant

¹ [Clean Power 2030](#) - National Energy System Operator

² [DFES](#) - SSEN



development for the entire energy system in the UK which may unlock or require changes to the regulatory approach taken by Ofgem. However, integrating RESP into the price control process will be a complex process carrying some risk. See our answer to Q17 on what NESO and the tRESP should focus on first to best enable DNOs better strategically plan for ED3.

- **System flexibility:** Ofgem’s framing on flexibility broadly which aligns with our use of flexibility in our Net Zero First approach to system planning; we use Strategic Development Plans (SDPs) to ensure network interventions going through the Distribution Network Options Assessment (DNOA) process align with a long-term plan informed by future demand projections. Our SDPs consider flexibility an essential component in the toolbox which can help manage temporary changes to network requirements or supply chain constraints. However, they recognise that in some cases, deploying flexibility to defer network investment, especially strategic investment, cannot be justified when a long-term view is taken (see our answer to Q17). We are also still fully supportive of collaborating with the Market Facilitator to drive a seamless flex provider experience, improve liquidity and reduce overall system costs.
- **Connections:** the huge increase in projected connections in ED3 will be a significant challenge for DNOs. This will bring major planning, workforce, supply chain and logistical challenges. See our answers to Q34 – Q37 for our view on how the regulatory framework can best incentivise the required behaviours from DNOs.
- **Climate resilience:** Climate change is already posing a significant challenge to our network in ED2, and climate resilience should be included as a driver for change at ED3. We have made good progress embedding climate resilience into decision making processes. However, as we enter a period of unprecedented network build, more focus from Government and Ofgem is required to ensure DNOs are incentivised and funded to provide resilient networks that are fit for purpose now and in the future (see our answer to Q57).

2. What are your views on our overarching objective and proposed consumer outcomes?

We would challenge Ofgem on whether the proposed overarching objective for ED3 is sufficiently ambitious. We think it should capture the need to ensure the energy transition is delivered at Distribution in the most efficient way over the long-term, for current and future generations of customers.

This reflects the need to take a long-term, intergenerational approach to the net zero transition, which is necessary in order to achieve the most efficient network transformation over several generations of bill payers. At SSEN Distribution, we are placing an emphasis on long-term planning and having a long-term strategy in place. We see RIIO-ED3 as a clear stepping-stone for achieving longer-term net zero goals. In that



context, there is a risk that Ofgem’s emphasis on “least cost” in the proposed overarching objective is misconstrued. The cost impact to customers should not be considered solely within the context of a single price control, as driving down costs artificially in one price control can increase costs and reduce efficiency of delivery in the longer term. Instead, Ofgem should focus on ensuring the framework enables the right decisions to intervene on the network to be made at the right point in time, with a view to 2050 delivery. This approach would minimise overall system costs of reaching net zero rather than prioritising short-term reductions that increase long-term costs. We think this approach aligns with Ofgem’s duty to protect current and future consumers, and with the direction of travel set out on flexibility. Please see our responses to Q14 and Q25 for further details.

In addition, the proposed objective has a good focus on enabling the necessary capacity to achieve decarbonisation goals (which satisfies Ofgem’s net zero duty). However, we think it is important to explicitly recognise the role that DNOs play in driving local economic growth, by facilitating a net zero transition for homes and businesses. This would satisfy Ofgem’s sustainable growth duty. We provide further commentary of the proposed outcomes below. We would encourage Ofgem to test the overarching objectives and proposed outcomes further with customers.

- **Networks for net zero:** we welcome the focus on a strategically planned network, and the emphasis on the need to provide additional capacity for users. We refer Ofgem to the previous paragraph on the concept of “least cost”. We have significantly developed our thinking in this space and are the first DNO to develop SDPs. These provide a blueprint for long-term electricity system needs into 2050 at each of our Grid Supply Points (GSPs).
- **Responsible business:** at SSEN Distribution, and as part of the wider SSE Group, we are proud of our track record in this space. We were the first DNO to publish a Just Transition Strategy, develop Vulnerability Future Energy Scenarios (VFES), set a 1.5°C science-based target for emissions reduction, and adopt nature-based solutions for carbon removal.³⁴ As such, we welcome the emphasis on responsible businesses. We note that the framework needs to evolve to reflect the challenges we collectively face, including the impact of climate change, changing customer expectations and the need to attract investment into the sector.
- **Resilient and sustainable networks:** we welcome the emphasis on resilience throughout the document – particularly on climate, workforce and supply chain resilience, as well as cyber. These are important challenges which we will need to navigate in the RIIO-ED3 period. The regulatory framework must therefore enable

³ [Just Transition, Vulnerability and Future Energy Scenarios](#) - Regen

⁴ [ED2 Environmental Action Plan](#) - SSEN



the right investment and support longer-term thinking on workforce and supply chain resilience. As above, network operators would benefit from clear direction on what level of climate resilience Ofgem and Government expect to be delivered, given the context of increased climate challenges.

- **Smarter networks:** data and digitalisation have a central role to play in the energy transition, so we welcome its inclusion as a consumer outcome. We were the first DNO to publish half-hourly smart-meter data, and we are working with NESO on how it will use the future Data Sharing Infrastructure (DSI) to deliver RESP. Ofgem must ensure that DNOs are fully funded to invest in the underpinning data and digital architecture required, and also ensure we are able to attract and retain technology professionals with the requisite data skills.

Please see our answers to the relevant questions under each outcome section for further details on our position.

3. Do you agree that the network investment elements of the framework should be more input based?

Our responses to Q3, Q4, Q7 and Q8 must be read together.

The concept of ‘input’ can be interpreted in different ways, with significant implications for the regulatory framework.

At one extreme, a model which prescribes ‘input’ in terms of very granular, specific, detailed deliverables/ solutions with limited opportunities to deviate, would result in greater regulatory involvement in the day-to-day running of the network. This would remove agency from the DNO but increase risk for the DNO since it would limit our ability to manage network risk, heightening risk of non-compliance with obligations. To address this, the framework would need to be adjusted to transfer risk to another party, such as Ofgem or NESO. As acknowledged by Ofgem, this model would also reduce efficiency and innovation while imposing significant resource demands on the regulator. There is also a risk that investment would be delayed if Ofgem does not have the capacity to process ‘inputs’. Furthermore, Ofgem must consider the regulatory burden this approach would place on DNOs, and the extent to which this is value for money for consumers and does not distract from the focus on delivery.

At the other end of the spectrum, a model in which ‘inputs’ are prescribed at a strategic level, for example the scenario a DNO should use to plan its network or the strategic needs associated with a region, could help drive certainty, lighten regulatory burden and accelerate investment. This would be one of the key inputs to DNO planning. This would still be compatible with an incentive-based model of regulation and the use of totex, therefore potentially avoiding some of the pitfalls outlined above. However, this may still have wider implications dependent on how the model is implemented. There will also be



interactions with other components of the framework, not currently being consulted on, including the Business Plan Incentive (BPI), the Totex Incentive Mechanism (TIM) and the detailed cost assessment methodology.

Ultimately, Ofgem needs to clearly articulate what issue a move towards granular input-based regulation is seeking to address and needs to consider the range of tools that it has available to address it.

4. Do you agree that we should consider introducing additional controls around network investments and what features should these controls contain?

When thinking about regulatory archetypes and controls around network investments, Ofgem should be guided by the key challenge they are trying to solve at RIIO-ED3. We note separate references to concerns around “under-delivery”, “under-investment”, “underspend” and “duplication”. In some parts of the consultation, the top risk in a ‘new risk hierarchy’ is identified as “delayed network build, or not building capacity right first time”. As a general point, Ofgem should provide a clear articulation of the problem(s) it is trying to resolve to ensure all parties can discuss associated regulatory questions with precision.

Existing Tools available to Ofgem

Ofgem should first look to the existing toolkit and ensure all components of the current framework are working together and in harmony. This seems a logical starting point, rather than introducing new controls and thereby more complexity into an already intricate regulatory framework.

Existing tools and mechanisms include:

- **The BPI and Cost Assessment:** concerns around under-investment could be addressed by ensuring the BPI and cost assessment do not drive an artificial race to the bottom, by focusing overly on reducing cost within period over delivering long-term benefits to consumers.
- **Price Control Deliverables (PCDs):** targeted use of PCDs for larger projects can help ensure DNOs are held to account where necessary, addressing concerns around under-delivery or under-investment. In RIIO-ED2, Ofgem decided that bespoke PCDs would only apply to projects over £15m. The reason for this was that Ofgem recognised the regulatory burden associated with PCDs, and noted “that the benefit to consumers of accepting a proposal as a bespoke PCD is not outweighed by the costs associated with its administration.”⁵ PCDs must also recognise that delivery can sometimes be affected by factors outside of company

⁵ [RIIO-ED2 Methodology Decision: Annex 1](#) - paragraph 3.31 - Ofgem



control, or that the scope of works can sometimes evolve, and may not be fully suitable for all projects.

- **NARMs** are an example of a PCD/ financial incentive that works well to incentivise delivery and give a degree of flexibility within the deadbands to allow for changing investment needs. Regarding concerns of duplication, we are already able to remove assets identified for health-based intervention under the NARM framework from the non-load program if they are funded under a load-related investment. This removes the risk of inefficiencies. Ofgem recognised that this approach was valid in the context of transmission, and it is unclear why this approach would not be suitable in the context of Distribution.⁶ As outlined in our answer to Q56, we would welcome further discussion with Ofgem regarding how the current regulatory reporting framework could evolve to take account of the multiple drivers and multiple benefits of one investment. This could mean the reporting framework is increasingly able to be solutions-focused, rather than merely cost-focused.
- **Use It or Lose It allowances (UIOLIs)**: this tool is useful in limited and specific circumstances where Ofgem has concerns around delivery of smaller value initiatives. However, UIOLIs are not subject to the TIM which can create issues with financeability and efficiency. It increases risk to DNOs due to both less predictable allowances and underfunding if scope changes are experienced over and above the allowance. Additionally, UIOLIs not being subject to the TIM removes the incentive for efficiency seeking behaviour, instead incentivising DNOs to spend the full allowance to deliver an output rather than deliver an output in the most efficient way. For these reasons we would not welcome an expansion of UIOLI application in RIIO-ED3.
- **Volume drivers**: while we see volume drivers as tried and tested tools that can flex downwards as well as upwards based on delivery requirements, there is a risk in the current context that unit rates are not reflective of actual cost of delivery. Instead of being able to reprioritise and deliver less for the same pot of allowances as with a totex approach, under a volume driver DNOs could be materially underfunded regardless of volumes delivered. For this reason, where volume drivers are used, there must be confidence in unit rates.
- **Reopeners**: we see these mechanisms as an appropriate way to account for genuine uncertainty when setting ex ante allowances at the start of a price control. We would like to stress, however, that the current administration of uncertainty mechanisms leaves DNOs in a position where we face uncertainty in funding and significant regulatory burden which is not efficient for consumers. The sector is in an environment where supply chain slots must be committed to as early as

⁶ [RIIO-3 Sector Specific Methodology Decision – ET Annex](#) - paragraph 2.249 - Ofgem



possible, and we have found that in order to deliver projects within ED2 we are having to commit to contracts in advance of Ofgem Determinations.

- **Totex Incentive Mechanism (TIM):** the TIM is a tried and tested mechanism that ensures a share of any underspend is returned to customers and incentivises DNOs to find operating efficiencies. This can help address concerns around underspends – at SSEN Distribution, we do not recognise the implication that the TIM is driving inefficient underspend.
- **Return Adjustment Mechanism (RAM):** the RAM, which has yet to be tested, is designed to enable Ofgem to intervene where it considers that returns are above expectations at the time of setting the price control. This can help address concerns around underspends and unjustified under-delivery, as it includes totex outperformance. Not all of these mechanisms are covered in the consultation, however Ofgem should consider how all different components of the framework can work together to deliver a positive outcome for consumers in the context of net zero.

Balancing controls with innovation and efficiency

We recognise the need to ensure DNOs are held to account for delivery – and we think the above existing tools work well in this regard. However, this must be done in a way that continues to drive innovation and efficiency. Any proposal that disproportionately reduces fungibility, or indeed removes totex altogether, could have significant implications and be detrimental to the ultimate outcome it is trying to drive for RIIO-ED3. Ofgem should make sure that any regulatory tool or control used in RIIO-ED3, existing or new:

- Avoids restricting DNOs' ability to make trade-offs under totex **restricts deliverability** by limiting our ability to align drivers and respond to changes on the ground. This also restricts our ability to align outages.
- Recognises that DNOs bear the **risks associated with under-delivery currently**, including network risk and risk of non-compliance with obligations. This means we need the flexibility to make decisions that are required and respond to change. As a simple example, in RIIO-ED2, we were not funded in Final Determinations for certain safety-critical activities (tree-cutting). As a result, we had to re-prioritise activities to enable us to meet our safety obligations.
- Considers the potential **unintended consequences** of any significant reduction in fungibility and the risk of driving **sub-optimal behaviours**. As already stated, this includes reducing innovation and efficiency, but also potentially incentivising DNOs to deliver works that are no longer required for fear of penalty.



Criteria for framework

Building on this, we think Ofgem should set clear criteria for determining the right regulatory framework. We propose the following principles which could be helpful when deliberating which regulatory archetype is most suitable:

- **Alignment with overarching objectives:** does the framework align and actively facilitate the overarching objective? As above, the overarching objective should focus on achieving the most efficient network transformation over multiple generations of bill payers.
- **Holistic approach:** do all the components, tools and mechanisms in the regulatory framework work effectively together to deliver the overarching objective?
- **Balance between efficiency/ innovation and under-delivery and under-investment:** does the framework still leave space for DNOs to innovate and drive efficiency in delivery across a long-term programme of work?
- **Allow flexibility and enable DNOs to manage risks:** does the framework allow sufficient flexibility for DNOs to respond flexibly to changes, and make trade-offs that enable to manage risks they bear the consequences of?
- **Be proportionate and suited to Distribution:** does the framework recognise the nature of Distribution network investment, which is generally lower value higher volume, and more programmatic in nature, compared to transmission?
- **Support financeability and investability of DNOs:** does the framework provide sufficient certainty to attract long-term, stable investment and ensure that activities can be financed effectively?

Our responses to Q3, Q4, Q7 and Q8 demonstrate that a move to restrictive inputs and limited fungibility does not meet the criteria set out above.

Finally, Ofgem is also silent on whether it still considers that the regulatory framework should enable a good performing company to earn additional returns. This is a fundamental question that will have wider implications for how the regulatory framework is designed and would likely impact our ability to attract investment into the sector.

5. Do you agree that the incentives on DNOs will need to adapt from RIIO-ED2 and if so, how?

We consider that the RIIO model of incentive regulation has worked well and continues to be fit for purpose. However, we agree evolution is needed in some areas.

We provide some information in response to this question – however, please see also our response to Q31 and Q32 on customer service incentives, Q34 – Q37 on connections incentives, Q38 and Q59 on reliability incentives. We note that Ofgem is only consulting on a subset of incentives; we will need to understand the full incentive package to provide a fuller response.



As a general point, Ofgem will need to consider to what extent each incentive is still fit for purpose in the context of (i) a significant increase in activity to deliver net zero amid ongoing planning, supply chain and delivery constraints, (ii) changing customer expectations, (iii) a changing climate, (iv) connections reform, and (v) factors outside company control. Each incentive interacts with other components of the regulatory framework which could impact our ability to meet targets, and Ofgem should also confirm that the ability to meet baseline targets should be funded through the price control.

These factors will affect how Ofgem designs incentives and sets key parameters, for example, incentive rates and targets. This ensures that DNOs are not incentivised to spend to avoid penalties in a way that exceeds value to consumers. For all incentives, Ofgem should seek to finalise design and set key parameters through the Sector Specific Methodology process. This is so that DNOs have sufficient visibility of the framework so as to align their plans. In line with statements made by Ofgem at RIIO-ED2, we expect that DNOs will be funded through their baseline business plan to meet core targets.

Customer service and vulnerability incentives

The Broad Measure of Customer Satisfaction (BMCS) incentive has driven up customer service standards with DNOs achieving consistently high scores. However, it misses key elements of customer service like trust, relationship management and societal impact. This is a significant blind spot in the current incentive. We would recommend a sector-wide working group be set up to review alternative approaches to the BMCS that provide a more robust, cross-sector comparable measure of customer satisfaction. Please see Q31 for further detail on BMCS evolution. Likewise, the Customer Vulnerability Incentive could be reviewed, especially the PSR reach element, to ensure there is not an overfocus on sheer number of customers registered, which can detract from the level of service vulnerable customers receive. See Q32 for more.

Reliability incentives

The societal shift towards electrification and growing impact of climate change mean we think the time is right for a full review of IIS to avoid disproportionate penalties for DNOs for events or trends that lie ultimately outside their reasonable control. This review should, at the very minimum, revisit the exceptional event threshold, which is not reflective of severe and frequent storms (with very violent and disruptive storms not being included in the exemption). It should also test the category of Planned Interruptions in the context of widespread electrification to make sure DNOs are not disproportionately penalised for doing the right thing and intervening to prepare networks for net zero. Please see Q38 and Q59 for more detail on regulating reliability.

Connections incentives



We believe that ED3 offers an opportunity to review whether the Time To Connect (TTC) incentive is still fit for purpose, as we are increasingly finding that, at times, we have to balance delivering a truly great service against timeliness due to TTC penalties. A change to a 'site ready' approach may be more appropriate for post acceptance TTC to quantify how DNOs can respond when customers are ready for their minor connection to be completed and, by allowing for delays outside our control, will be a truer reflection of performance. Please see Q34 and Q35 for more detail on TTC incentive.

In terms of the service provided by DNOs to connecting customers, we believe minor and major connections should be treated separately as customer priorities differ. For major connections, customers value granular network data, upfront engagement with system planners, accurate quotes, and clear, flexible delivery plans - areas only partially covered by the current framework. For minor connections, priorities focus on application ease, process support, and timely delivery, which are well-addressed by existing measures. However, we see merit in simplifying and consolidating complex reporting requirements for minor connections to reduce administrative burden and improve customer outcomes. Please see Q36 for additional detail on connection service.

6. Do you agree that there is still a role for reopeners in ED3, particularly given the timing of the future full RESP output and how should these be triggered?

Overall, yes, we agree there is still a role for reopeners in RIIO-ED3. However, reopeners are highly resource intensive, not only for DNOs but also for Ofgem, and over-reliance on reopeners could result in a delay in investment that is necessary to achieve net zero goals.

Before introducing a reopener in the regulatory framework, Ofgem must ensure baseline funding is set at a sufficient level to account for investment that is certain: reopeners, and uncertainty mechanisms more generally, must only be used where there is genuine, significant uncertainty.

When it is clear a reopener is needed, Ofgem must ensure:

- Speed and agility of decision-making: regulatory burden must be reduced to enable decisions to be made in a speedy and agile way, ensuring that investment is not delayed.
- Ensuring all uncertain costs are captured: eligible funding must include any well-justified indirect costs associated with the capex, recognising in particular the increasing costs of delivery in the current environment and skills/ resourcing constraints.

For load investment in RIIO-ED3 in particular, Ofgem should ensure baseline allowances are set sufficiently high to enable net zero investment to go ahead. Reopeners or uncertainty mechanisms should only operate beyond a high baseline scenario.



The logical approach would be to link this to RESP updates or refreshes. This should lighten the regulatory burden significantly, by ensuring strategic need underpinning network proposals is validated early and requiring a lighter touch review from Ofgem only. However, this could miss additional investment requirements that are in-period, or indeed changes in scope associated with large projects which could drive costs up in between RESP publications or RESP refreshes.

7. Using RIIO-ED2 as the counterfactual, what alternative regulatory models or characteristics are needed in ED3 to ensure the DNOs deliver the above consumer outcomes? What are the trade-offs we should consider?

Our responses to Q3, Q4, Q7 and Q8 must be read together.

As a starting point, we consider the RIIO model is broadly fit for purpose. Amendments will be required, as discussed throughout this consultation response, to ensure it can support delivery of net zero in the context of increasing climate change, workforce and supply chain challenges, and changing customer expectations.

In our response to Q4 above, we set out criteria which Ofgem must consider when deciding on the right archetype for RIIO-ED3. Our view is that the current incentive-based framework should be the starting point for RIIO-ED3.

“Incentive Regulation RIIO-ED2”: the current regulatory model, evolved in some key areas (see detail in response to Q5 and in later parts of our response), should be the basis for the regulatory framework governing the core of DNO activity. Primarily, this is because the majority of DNO work takes the form of thousands of smaller capital projects and programmes, especially at the Low Voltage (LV) and High Voltage (HV) levels. The heterogeneity of these requires an agile approach to planning and delivery, making a proscriptive ‘Plan and Deliver’ model with the regulator taking a more ‘hands on’ approach less suitable than the current incentive-based approach with set outputs. We also consider the RIIO model to have delivered considerable benefits to consumers, for instance driving up reliability standards for consumers and incentivising innovative solutions to shared problems.

“Plan and Deliver”: if introduced, our view is that this should be focused on RESP providing strategic inputs under “plan”, using a combination of tools to hold DNOs to account for delivery in a proportionate manner. Our current view is that this is most likely to apply in the context of large, strategic load projects, where “Plan and Deliver” can add real value by driving additional certainty of need, with a range of tools used in a way that reflects the nature of projects (e.g. large projects vs. programmes of work).

While ‘Plan and Deliver’ would likely be most suited to larger projects, at lower voltage levels, the focus should be on facilitating long-term programme delivery and a multi-price control approach. Ofgem could consider a version of ‘Plan and Deliver’ for large



programmes of work made up of smaller, very similar projects, that could span multiple price controls. This might be a way for Ofgem to lighten the regulatory burden by moving away from project-by-project justification, focusing instead on an overarching programme's transparent and robust decision-making processes. This could unlock efficiency gains and provide further long-term certainty regarding levels of future investment. However, this would require significant further discussion; the learnings of the Gas Mains Replacement Programme (Repex) could be a useful analogy and provide key learnings for how multi-price control programmes of work could operate effectively in practice. As above, this should be supported by the identification of strategic needs through the RESP process to support multi-driver interventions.

We note that Ofgem's proposed model for ED3 outlined in Figure 6 of the consultation has a greater focus on inputs and less spend fungibility than in the RIIO-T3 model of incentive-based regulation. However, it is not clear why Ofgem considers this more extreme version of 'Plan and Deliver' to be more appropriate in the context of Distribution. In particular, our understanding of the Transmission model is that the 'Plan and Deliver' model applies only to CSNP driven projects, with a mix of volume drivers, reopeners and UIOLs for other activities. However, Ofgem's proposed model for RIIO-ED3 means that some equivalent activity (e.g. at 132kV level) could be treated differently north and south of the border, and result in a disproportionate treatment of DNO activities compared to Transmission. We also note that the Transmission model includes delivery incentives, which would require more detailed consideration before introduction to Distribution.

Ofgem should be considering changes beyond the regulatory archetype debate, in particular thinking about how the regulatory framework can better enable activities that span multiple price control periods. For instance, our SDPs provide well evidenced blueprints about future network requirements and could provide the basis for longer term funding. In addition, SF6 replacement programmes can be forecast over the long-term and might be suitable for multi-price control funding. This evolution would be welcome and represent a pivot away from the current incremental approach with funding approved in 5-year cycles to a more holistic approach with planning at a system level. There are clear benefits to this approach: it would send clear signals to our supply chain and future workforce, thereby enhancing deliverability and achieving additional value and efficiencies through a whole system, holistic approach to network transformation, ready for net zero. A second evolution would be to simplify what has become an incredibly complex regulatory burden for both the regulator and DNOs to manage. A good starting point here would be only using uncertainty mechanisms where there is genuine uncertainty.

With regards to trade-offs, our responses to Q3, Q4, Q7 and Q8 point to key considerations. Our view is that some of Ofgem's proposal could create significant additional risk. For example, there could be negative impacts on our ability to deliver the



required increase in investment, limiting DNOs' ability to manage risk on their network, and increasing regulatory burden. However, as described above, retaining 'incentive-regulation' as the starting point, with potential targeted introduction of 'Plan and Deliver', would achieve the right balance, by enabling DNOs to invest for net zero at scale with greater certainty of need, and with a proportionate approach to holding DNOs to account.

Finally, Ofgem must consider the associated cost of a major, controversial change to the regulatory framework precisely at a time where investment will go up to meet Government net zero and growth ambitions. We agree that changes are needed to the regulatory framework – however, moving to an extreme and wide-ranging "Plan and Deliver" model without the full confidence of the sector would serve to erode our ability to be agile when delivering work and could introduce confusion which would further hamper our ability to deliver. Ofgem must consider how such a move would be consistent with its duty to consider sustainable economic growth, re-emphasised by the Prime Minister's December 2024 letter to economic regulators.

Ofgem has obligations under Section 5A of the Utilities Act 2000 to undertake an impact assessment for proposals that are "important".⁷ Any change to the price control framework, particularly significant ones like the proposed move away from the current regulatory archetype, is likely to involve significant impacts and costs on our activities, and impacts on consumers. An impact assessment on any such changes must therefore be carried out and consulted on before Ofgem reaches a final decision. We note that changes to regulatory archetypes would likely have much wider implications on the regulatory framework, including on elements of the framework not being consulted on here (BPI, TIM, detailed cost assessment amongst others).

8. Do you agree that the regulatory framework for ED3 should have features of the Plan and Deliver model for network investment and Incentive Regulation model for other elements?

Our responses to Q3, Q4, Q7 and Q8 should be read together.

Subject to the outcome of an impact assessment and further discussion on interaction with other regulatory mechanisms (e.g. TIM and the BPI) not consulted on here, we think that RIIO-ED3 could potentially incorporate some features of 'Plan and Deliver' for large, strategic capital load projects at the Extra High Voltage and HV levels. The 'Plan' element should be about driving certainty of strategic need and would be achieved by having tRESP and RESP inform the model by defining regional strategic need. An additional value would be embedding democratic legitimacy and accountability into the strategic planning process. Importantly, the input should be kept at a strategic level – more granular specification of needs and network optioneering should remain the

⁷ [The Utilities Act, 2000](#), Ch. 5A



responsibility of DNOs. The ‘Deliver’ element should be carefully and pragmatically designed, making full use of existing tools and ensuring that DNOs are held to account for what is under their control to deliver, as per our response to Q4. There may be a case for limited application of ‘Plan and Deliver’ at the LV level, where the strategic input from tRESP and RESP indicates a programme of largely similar, smaller projects is needed - but this needs further exploration.

A proportionate, limited use of ‘Plan and Deliver’ should sit alongside the established RIIO Incentive Framework, with RIIO-ED2 as the base to build on. Ultimately, one regulatory throughput that Ofgem should not lose sight of is the importance of deliverability. The regulatory model, regardless of the archetype it draws from, should make delivery easier for DNOs by enabling the flexibility and long-term certainty we need to deliver for our customers.

9. Do you think that there is a greater role for elements of ex post regulation or of cost pass through in ED3, either specifically in assessing cost changes resulting from changes to investment requirements during the period, or more broadly to reflect the changing context?

The role for ex post regulation

We do see some positive aspects to this approach, such as a simplified up-front process and the freedom for network operators to get on and deliver. We also note that ex post regulation is not new and already plays a role, e.g. through close-out processes. However, for this model to work in a way that avoids undue retrospective regulation, there would need to be clearly articulated outcomes and rules governing the ex post review. Greater ex post regulation would require a significant change to how the relationship between Ofgem and DNOs currently operates, and the regulator would need to be committed to the framework it has set up and carrying out a light-touch review only, and resist temptation to apply retrospective regulation. If this is not adhered to then the significant risks would outweigh any benefits.

Recent experience with reopener mechanisms demonstrates that there is a significant regulatory burden attached for both the regulator and DNOs. In some cases, this can mean there is a risk that necessary investment is delayed because the reopener mechanism does not proceed as expected. This is problematic for several reasons – including because it means DNOs have to engage our supply chain in advance of a determination on needs, and therefore, without an ex-post regime in place, we undertake considerable expenditure at risk.

As our answers to Q3, Q4, Q7 and Q8 make clear, our view is that the regulatory framework must be made up of primarily pre-determined ex ante allowances with uncertainty mechanisms only being used beyond a high baseline scenario. However, in the context of ED3 where DNOs will have to deliver at pace, alongside a significant



streamlining of the current reopener process, we think there may be scope for some ex-post mechanisms in very limited circumstances – for instance, where tRESP or RESP identified a new high priority network need that required swift delivery, and where waiting for confirmation via the reopener would risk capacity being delivered in a timely manner. An ex-post framework such as the Demonstrably Inefficient or Wasteful Expenditure (DIWE) approach would allow a DNO to complete work at pace while having the relative confidence that there would be a very high bar for disallowances.

Another application could be Real Price Effects (RPE) adjustments - as outlined in our response to Q43. The current RPE forecast is driving significant uncertainty and fluctuations to allowances. Our view is that an ex-post mechanism to true-up adjustments during close out may provide a potential tool to be considered in order to iron out the unexpected allowance fluctuations that are currently being experienced, and undermining DNO confidence.

The Role for Pass Through Costs

Pass through mechanisms are well-suited to costs that DNOs incur that are either statutory or are not influenced by increased operating efficiencies. Our view is that the current list of pass through costs is still appropriate for ED3. However, we would welcome a mechanism in ED3 to account for unexpected costs that are out with the control of DNOs - whether through a reopener, pass through mechanism or other suitable means.

Part 2: Networks for Net Zero

10. What is the potential availability of distribution-based flex across GB for DNOs in the short-term and on the journey to net zero during ED3?

In ED2 to date we have continued to build on our experience to grow and expand flexibility services in the network. This expansion has resulted in Overarching Agreements (framework-like contracts) with 21 different providers and more than 800 MW of flexibility services contracted with this continuing to increase. However, as noted in the consultation, filling volumes in specific locations and overall market liquidity and market competitiveness remains a challenge at this stage. Whilst we anticipate improvement to liquidity, challenges will likely persist in specific areas, particularly in the most remote areas of our network such as the island communities.⁸ Despite these challenges, we expect flexibility services will continue to be a key tool in the journey to net zero.

The challenges in Distribution-based network flexibility services are complex and the obstacles vary for different market participants and potential market participants. It is notable that system flexibility services and wholesale market signals can provide

⁸ Our Island Request for Information has highlighted additional barriers to entry for Flexibility Services in these communities with some learnings applicable on rural mainland areas as well.



significantly more revenue opportunities than local markets. These markets can also be easier for providers (particularly those working with domestic assets) to enter as aggregating across the country can have reduced risk and easier management. The combining of these services by market participants through stacking may increase participation in markets overall but challenges to this remain. We are continuing to work with the wider industry and NESO to improve the ability to do this whilst also ensuring the networks remain safe and secure.

We expect that over the course of ED3 some of the existing Distribution requirements for flexibility services may fall away due to the strengthening of wholesale market signals and innovative domestic tariffs which push more energy use to off-peak periods. A challenge for all DNOs is understanding where this will happen and by how much demand will shift. Current data trends are difficult to use to draw conclusions due to the over-representation of early-adopters and first movers within these data sets.

The success and functioning of time-based tariffs will significantly impact how flexibility services will need to evolve, and ultimately their availability during ED3. SSEN has experience of where controlled loads all move to the lowest price point resulting in localised peaks away from the typical windows – historically seen through energy storage heaters switched on overnight. Our demand diversification⁹ trial is investigating commercial solutions to the issues these localised peaks could cause if uncontrolled. Whilst this is one potential solution, we expect network requirements to need to evolve to accommodate this behaviour to avoid flexibility creating new network constraints in the future.

The evolution of Access Products will also impact Distribution flexibility through allowing more people to connect earlier and maximise grid utilisation. We expect the use of these to grow as offered connections become live and create new opportunities for flexibility service participation. We are continuing to develop and innovate in this space including the development of new products as industries decarbonise, such as time-of-use Access Products.

11. To what extent are global supply chain and workforce pressures contributing to longer lead times for delivery of network reinforcement?

Please read our answer to Q11 in parallel with our answers to Q62 – Q64.

Global supply chain pressures and workforce challenges, including a shortage of key skills and rising prices are a significant challenge. We are already feeling the impact of these, as outlined in Q62 and Q63, and are taking proactive steps to manage these. However, as the volume of work increases and existing challenges are exacerbated, if the right mechanisms are not introduced, we think supply chain challenges and skills

⁹ [SSEN tests innovative solutions in new electricity demand trial](#) - SSEN



shortages will significantly disrupt our ability to deliver timely network reinforcement in ED3.

This question focuses on longer lead times, but it is important to recognise that, without proactive management, global supply chain and workforce pressures also risk the cost-efficient delivery of projects too. For example, prices continue to be volatile with the effects of global inflation, economic and trade uncertainty, and the spiralling cost of materials still being felt. As outlined in the answer to Q63, there is a clear need to revisit the RPE mechanism to ensure there is a more realistic adjustment factor if indexation continues, and allowances are more reflective of market price changes experienced over and above that of inflation.

12. Do you agree that the risk and downside for consumers of network underinvestment in network reinforcement would be greater than the downside of overinvestment?

We agree with this characterisation of risk and recognise the change from a focus on stranding risk when overall load and distributed generation growth was slower and less certain to impact the network. Ensuring adequate capacity on the Distribution network, alongside a clear, consistent, and timely process for network connections, is essential. Without these, consumers may face barriers to adopting electric vehicles and heat pumps. Additionally, the electrification efforts of businesses and industries could be hindered, alongside the deployment of generation assets connected to the Distribution network, limiting access to wider whole system benefits. NESOs pathways and many other sources¹⁰ recognise that regardless of the exact pathway to get to 2050, a substantial bolstering of the Distribution network will be required, significantly reducing the risk that load investments will not be utilised.

It is still important to ensure value for money for consumers in meeting overall capacity needs; in an environment when overall network usage is increasing and growing more complex, we must keep pace with the capacity needs that drive the economy and have a wide array of indirect social, economic and environmental benefits, such as accelerating the delivery of housing, facilitating business growth, and enabling air quality improvements through providing electric vehicle infrastructure. In this new paradigm, there is much greater scope for achieving cost reductions through strategic approaches that achieve economies of scale.

We support and use approaches to investment that: recognise the value to society of releasing capacity in a timely way; manage risk by maintaining optionality where economic; are targeted to delivering on our communities' ambitions, and exploit

¹⁰ [Terms of Reference – Distribution networks study](#) - National Infrastructure Commission



synergies through ambitious programs of work to drive value for bill payers now and in the future.

13. What are the benefits and risks to deliverability if network reinforcement is deferred to future periods?

Deferring network build into future price control creates risks in the context of the step-change in investment required to deliver net zero. These include pushing costs onto future consumers, limiting our ability to work closely with our supply chain to enhance deliverability, ultimately endangering our ability, as an industry, to play our role in delivering net zero.

There are some benefits to using flexibility to defer reinforcement in some limited circumstances. As directed in business plan guidance, our ED2 plan was built seeking to maximise economic benefits of using flexibility to defer network reinforcement. The benefits we considered included more time to understand the development of network needs and thus choose a better long-term solution, providing an additional market and revenue stream for flexibility that can increase liquidity and availability, and short-term benefits to current bill payers of deferring capital expenditure (though this could in turn represent a cost to future billpayers).

While these benefits did justify our plans to expand flexibility procurement for ED2, going forward they must be considered against the contrary pressures to deliver significant capacity uplift across the network at unprecedented pace and scale. Across our networks, and especially at the LV level, the focus should be on long-term delivery which might extend to a multi-price control approach, possibly taking learnings from the Gas Mains Replacement Programme (Repex). These approaches can be incompatible with deferral, as the synergies of strategic programmes can be lost if deferral causes some works to be unsynchronised.

Rising power demands driven by decarbonisation often outpace the pace of network reinforcement, necessitating a degree of forward planning to minimise the occurrence and duration of capacity constraints. Furthermore, the supply chain is best positioned to support large-scale programmes of work when workloads remain steady over defined periods, enabling the necessary investments and optimisations. In this context, deferrals – if overused – can lead to supply chain uncertainty, overlook the benefits of earlier delivery synergies, and risk the emergence of capacity constraints should demand exceed available flexibility in the required areas.

The right approach to network reinforcement should therefore focus on the right balance between uncertainty, efficient delivery, and economic detriment due to capacity bottlenecks. We believe there is a significant role for anticipatory and strategic investment to support increasing capacity requirements and linked economic activity.



We have therefore designed our Strategic Development Plan (SDP) methodology to help us plan the right intervention at the right time and make long-term decisions that minimise whole system costs to the benefit of current and future billpayers.

Flexibility to defer investment should remain a tool for DSOs to be targeted to scenarios where there is significant uncertainty in long-term forecasts, or to allow more efficient use of the supply chain. As noted in the consultation, there are a wide array of other use cases for flexibility which are also critical to delivering net zero, at the Distribution and system levels, and we will continue to drive and support greater use of Distribution connected flexibility across a range of uses.

14. What do you see as the role of distributed flexibility, both in the short and longer term, to manage distribution network constraints?

We have successfully used Flexibility Services and Access Products to deliver value to end customers, accelerate connection to the network and reduce the use of diesel generation. We therefore believe that Distribution Flexibility Services and Access Products are a key tool for DSOs to manage the network optimally.

We continue to refine and enhance our processes for Flexibility Services, which we anticipate will remain a key component of our approach to network management. Flexibility Services are particularly effective in addressing network requirements which are expected to be temporary, whether due to changes in network configuration, demand patterns, or those driven by outages or faults. They also provide valuable support in situations where reinforcements face supply chain, resource, or access constraints. By leveraging Flexibility Services, we can facilitate the coordination of work, smooth demand peaks, and mitigate delays arising from supply chain challenges. We continue to expect to use flexibility in this way throughout ED3, and we welcome the consultation recognising these use cases and the critical role flexibility will play.

A collaboration between SSEN and NERA¹¹, highlights that optimal benefit from Flexibility Services can be achieved when combined with Strategic Investment. This can be used to ensure that Flexibility Services are not exclusively focused on resolving Distribution constraints but, where economic to do so, they can be made available to NESO for the use in Ancillary Services, which is often only achievable when the Distribution network they are connected to is not under an active constraint. We continue to work across industry to ensure that where there are needs for both Flexibility Services at a Distribution level and wider energy level, we are moving to a whole-systems approach to maximise overall benefits.

¹¹ [Recommending Improvements in Regulation to Better Incentivise Strategic Investment in GB Electricity Networks](#) - NERA



We do also support the view in the consultation that there are limitations in the use of Flexibility Services. Without considering these, and the whole-system impacts of Distribution flexibility, there is a long-term risk of sub-optimal development of the approach being used. Pivoting this to combine the best of flexibility and reinforcement programmes will be key to delivering net zero. We support a similar approach with Access Products, combining temporary curtailment options with a future reinforcement, allowing accelerated connection.

Distribution Flexibility Services and the NESO Demand Flexibility Services have provided a strong impetus for innovation in the market with new behind-the-meter Flexibility Service Providers and time-of-use tariffs offered by suppliers. This has been particularly successful at increasing access to domestic flexibility which was not accessible through existing tools like Access Products. We would expect some of the use cases for purchasing Flexibility Services currently will move from a directly purchased service to an implicitly delivered services over ED3 as these providers begin to follow wholesale market price signals and with increased in Curtailable Connections. We also recognise that wholesale markets are where flexibility value can be maximised and has longer-term benefit for participants. A particular challenge for Distribution markets under the ‘Flexibility First’ commitment is individual locations are only required for a relatively short period of a few years, which can make it difficult to justify in the investment to deliver flexibility on the basis of a Distribution service alone.

Consideration should therefore be given to the potential evolution of wholesale market prices signals and the associated risks of schedulable domestic load shifting. This may lead to a shift in Flexibility Services towards managing the impacts of implicit flexibility within local areas, rather than consistently relying on the procurement of an explicit service.

Overall, we expect flexibility to continue to evolve over ED3 and into the long-term, with four key areas to highlight here:

- A shift towards implicit flexibility being delivered by providers to wholesale market signals.
- Distribution networks’ to increasingly facilitate access to NESO system flexibility services by providing access to a network that is not constrained to allow this participation.
- Continued use of DSO Flexibility Services to enable outages, reduce diesel generation usages and optimise the network investment programme.
- An increasing need for services to begin to manage localised impacts of herding behaviour in implicit flexibility.



15. How do we ensure that network flexibility is used only when it is in consumers' long-term interests in ED3?

Managing long-term and short-term interests in the use of network flexibility is a challenge. While the Common Evaluation Methodology (CEM) tool effectively considers the short-term interests of economic value as well as capturing other benefits and costs, quantifying the long-term value is more difficult, with limited guidance provided within the methodology.

A key difficulty in trying to capture the long-term benefit is quantifying the benefit that Flexibility Services bring, such as enabling delivery and deferring carbon emissions associated with construction. These must be balanced against the potential limitations with using Flexibility Services, such as: reducing the availability of System Flexibility to NESO, limiting connections in some areas (due to a limit on the additional capacity that flexibility can enable), and running the network at increased risk.

We would highlight the work we have completed with NERA and Baringa looking at quantifying some of the wider benefits of Strategic Investment to provide an updated Strategic Investment tool that aims to understand some of these aspects. We suggest a similar approach is taken to look at the wider benefits or risks in Flexibility Services and this is used to update the CEM tool to provide a clear process for this assessment considering these issues that can be consistently and transparently applied across all the DSOs.

Our Strategic Cost Benefit Analyses (CBAs) are one component of our network planning process, where our SDP and DNOA methodologies help us plan the right intervention at the right time and make long-term decisions that minimise whole-system costs to the benefit of current and future billpayers.

16. How are unexpected constraints dealt with currently? How quickly can these be eased, and what is the impact of these unexpected constraints (e.g. on LCT uptake)?

Constraints arise when the network capacity is insufficient to safely facilitate the power flows that would arise without intervention (i.e. through a market solution 'constraining' generation to change network flows). An incident, such as a fault that causes a loss of power, is not in itself a constraint, however post-fault constraints could be required to manage the flows on the non-intact network.

In general, most constraints don't arise suddenly, instead impending constraints can often be revealed by system studies looking at the implications of new connection requests. If a large connection request comes forward at a substation nearing full capacity, this doesn't lead to a 'constraint' per se but may mean that a connection at the full capacity requested may take time to realise. Significant and concentrated Low Carbon Technology (LCT) uptake could also drive local substations into overload



conditions - in this case we would seek local flexibility to manage flow in the short-term and plan a network upgrade to future-proof the area in question. While flows on the lower voltages of the network are not universally monitored, increasing uncertainty, our Network Visibility Strategy¹² is lowering this risk. Our network visibility approach will give us 100% visibility of power flow from the higher voltages through to the LV assets across our network through the installation of LV monitoring on 19% of our secondary ground-mounted substations, direct embedded measurement of selected plant, penetration of smart meters, modelling and analytics.

Our approach is to seek to avoid ‘unexpected’ constraints through the quality of our network visibility and forecasting work, ensuring we have a good understanding of where overloads could occur and where capacity is at risk. In the medium-term we will look at innovative ways to overcome any constraints that do arise as quickly as possible, which has resulted in approaches such as West London ramping¹³ and T-D limits¹⁴ to allow connections to proceed with minimal constraints.

17. Do you agree that the tRESP output outlined for early 2026 will help create a level playing field for DNOs’ business planning and support the ED3 objective and consumer outcomes?

We support the RESP and a meaningful tRESP contribution to the setting of ED3, as well as the permanent arrangements for RESP having significant interaction with the price control. RESP and tRESP should be focused on facilitating the regulatory approval process, lightening the burden on Ofgem and DNOs.

The tRESP should focus on doing such activities as NESO is ready to deliver throughout 2025 and into early 2026 at the very latest. In particular, NESO and Ofgem should indicate which pathway DNOs should plan their request for ED3 baseline allowances against as soon as practicable, and such a pathway should be aligned to the CP2030 mission.

The descriptions that Ofgem set out can be interpreted in several ways so we have added some further detail of what components we would most value in a tRESP:

- We would like the NESO and Ofgem to provide clear, early guidance on what pathways we should develop our plan with; we are currently discussing next year’s DFES requirements with our supplier.
- It would be valuable if NESO were able, as a RESP trial, to undertake some board-lite style engagement to determine some ‘local opportunities & priorities’ - what would be most valuable is something our plan could be demonstrably aligned to.

¹² [Network Visibility Strategy](#) - SSEN

¹³ [West London Ramped Capacity Trial](#) - SSEN

¹⁴ [Technical Limits at our Grid Supply Points](#) - SSEN



- Through the Energy Networks Association (ENA), work is ongoing to achieve methodological consistency for DFES wherever practicable - NESO involvement in this process for independent validation would be welcome, as well as a shared understanding of where divergence is required.
- We look forward to working with NESO on coordinated stakeholder engagement. In the next phase of RESP development, clearer delineation of the purpose and scope of different engagement activities would be most helpful. For example, this could clarify the contrast between DSO-led Local Authority engagement for meeting specific and localised plans, and a wider, ‘regional fora’ style of engagement for building consensus around energy ambitions. These engagement activities, done jointly with NESO where appropriate, will help identify strategic needs to inform our plan.

On top of these areas aligned to Ofgem’s example activities in the consultation, we believe 3 other areas of activity could be delivered in time to influence ED3 and would be constructive:

- Engaging with definitions of strategic and anticipatory investment to allow more detailed discussions on evidence requirements and permanent RESP roles across different investment categories.
- A methodology for independently ensuring alignment across Transmission-Distribution boundaries: Are needs being flagged and addressed in the most strategic way?
- An exploration of the ‘in-development register’ concept, linked to connections reform: How do different local area plans account for the wide range of potential developments and their varying likelihood of realisation?

We need sufficient time to understand the scope and outputs of the tRESP to build into our ED3 processes, such that any available regional pathways, objectives or priorities can be reflected in our business plans. Conversion from a pathway to a credible business plan is a lengthy process with multiple steps to convert technology pathways to granular forecasts of load impact, followed by assessing the impact of loading patterns on network requirements, optioneering to resolve these, and optimising with our other drivers of investment such as condition-based replacement. Pathways should align with or build on existing FES/ DFES pathways: this is critical as it will enable DNOs to start planning now and ensure that any regional pathways can be incrementally built on existing plans, thereby avoiding unnecessary rewrites of Engineering Justification Papers (EJPs).

NESO’s ‘no surprises’ approach to RESP pathway development is welcome, and any inputs that can be provided to the DNOs as part of the tRESP should be shared as soon as possible. Working flexibly will be key to producing robust, high-quality evidence for



network plans and ensuring the most up-to-date information is accounted for wherever possible. This could take the form of agreed methodologies to update EJPs which are based on network studies done on a fully analysed prior pathway or scenario. This would require common support for a lighter touch process to take account of changes to inputs (i.e. updated pathways), without attempting to rerun full DFES-to-load forecast processes.

Finally, we note that the introduction of tRESP and RESP is likely to have wider implications for the design of the framework, in particular cost assessment. Please see Q44 for more detail on this.

18. Can anticipatory network reinforcement be used to smooth the long-term build profile to avoid creating pinch points for the supply chain and workforce? What are the risks and trade-offs?

Anticipatory investment describes a wide range of activities - and will have different drivers depending on context. For example, anticipatory investment on the LV network is likely to be based on achieving synergies through a programmatic approach, even if not all assets within scope are at short-term risk of overloading at the point of intervention. These synergies may well include smoothing of the work required of the supply chain and DNO workforce, which will have related efficiencies. At the primary network level, anticipatory investment will depend on more project specific synergies that can be achieved - such as access and outage requirements, but again synergies that can be achieved in the supply chain.

As a general point, long-term certainty of work for the supply chain, which can be achieved through some degree of anticipation of network needs over a longer timespan (7+ years), coupled with sufficient baseline funding in the price control, can enable us to make the necessary preparations and find economies of scale early – see our answer to Q62 for more detail.

The key risk associated with anticipatory and strategic investments is not the temporary stranding of assets built in anticipation of net zero requirements, as these are highly likely to materialise in the longer term. Furthermore, the regret cost of building a few years early is low compared to the regret of acting as a blocker to net zero. However, there is the risk of incorrect prioritisation and completing works in the wrong order, resulting in capacity shortages while less urgent projects are completed. Therefore, forecasting and network visibility strategies will remain critical to the delivery of the right work at the right time. Our SDP methodology, described in other sections of our response, will play a key role in mitigating these risks.



Another risk is the transition between ED2 and ED3 acting as a cliff edge - see our response to Q20 for a discussion of the impact of baseline allowances being confirmed in fixed windows.

19. Do you agree that investment optioneering should aim to reduce the lifetime costs by sizing elements of works for long-term need, including considering the impact of thermal losses?

We agree that optioneering should aim to minimise long-term, whole-system costs. Since the beginning of ED2, we have evolved our approach to improve how we achieve these results, while bringing key stakeholders along with us. This approach includes our new SDPs, DNOA and Strategic CBAs for fully understanding lifetime costs and benefits and addressing the right constraints at the right time with the right stakeholder inputs and buy-in.

It should also be noted that thermal losses are a benefit category in the standard CBA template used for price control submissions. This in theory would capture the benefit where it can be studied. However, the standard CBA does not explicitly value capacity, so has a natural bias against strategic investment that the losses benefit would not typically offset - hence the need for a strategic CBA that addresses both value streams.

20. Is a 5-year price control (2028-33) the right duration to achieve the objective of securing timely network capacity for the net zero transition at least cost to consumers over the long run?

Whilst the 5-year price control window works for most DNO activities, the price control model as a whole presents an issue for Load investment, as it is tied to the certainty that works can progress and will be funded, as well as the lead time and input resources required for both high-value projects and high-volume, lower-value work programmes. This is a particular issue for Load investments due to their dependence on forecasts of load growth, but also a significant source of uncertainty in the price control. This is not insurmountable but means that as we approach the end of a price control, works that must be progressed in the next price control window don't yet have approved allowances which can impact the ability to efficiently plan and deliver these before the subsequent price control window is agreed.

In this context, when strategically planning the network, we look at least 7 years ahead (see DNOA and SDP process) for what interventions may be required. This goes well beyond the current price control and thus results in works we believe will be needed and will seek funding for in the future.

In seeking to secure the necessary supply chain, and drive efficiencies through a long-term workplan, the regulatory treatment of Load could allow for greater certainty in allowances within period, and for those that extend beyond the 5-year price control.



There are many ways this could be achieved while still allowing for the necessary regulatory scrutiny. Extending the price control alone wouldn't be an effective way to achieve this, as a change between price controls would still occur, introducing uncertainty in agreed works.

In addition to the discontinuity in funding certainty, requirements of electricity distribution also interact with other sectors with unaligned price controls- including gas distribution and electricity transmission. The RESP, which will sit across sectors and will produce outputs at a different frequency (the latest policy consultation suggested a plan update every 3 years) will be central to validating some reinforcement requirements, which will therefore not neatly align with price control windows across impacted sectors.

In summary, while the 5-year price control window suits most DNO activities, some consideration should be given to how longer-term RESP and network plans can progress with confidence in the Load space, without waiting for the next regulatory period.

However, we don't think the focus should be on trying to determine the 'right' length for a price control. Rather, Ofgem should consider how to design a framework that takes a long-term view of need and provides an appropriate level of certainty for investments that could span multiple price controls.

21. To what extent should the price control be more directive on specific anticipatory and strategic investments to achieve the 'networks for net zero' consumer outcome?

Please read this answer in conjunction with our responses to Q3, Q4, Q7 and Q8.

The price control could set clear expectations for delivery but, as stated above, early certainty in allowances makes this much easier to achieve and may be the necessary trade-off. Ultimately, the benefits of a more directive approach need to outweigh the costs.

An 'extreme' version of 'Plan and Deliver' where inputs are defined at a granular, rather than strategic, level, and the ability to make trade-offs under totex is limited or totex is removed altogether, would be disproportionate and will not enable efficient delivery of net zero goals.

There could be some benefits to plan and deliver if (i) it is largely limited to load, (ii) inputs are limited to strategic need identification by RESP/ tRESP (see Q17 for how we think tRESP outputs can help set the plan). Existing tools should be used to hold companies to account in a way that is proportionate such as PCDs, UIOLIs, volume drivers and reopeners.



An incentive-based model with RIIO-ED2 as the starting point should be maintained overall. Any use of a "Plan and Deliver" approach should sit alongside this and be proportionate and targeted.

22. Do you agree with our characterisation of strategic and anticipatory investment and our expectation that these activities would have different regulatory drivers and controls?

We note that 'anticipatory', 'strategic' and 'ahead of need' are all terms used interchangeably to refer to activities that are more proactive in nature. Hereafter we attempt to mirror the language used in the consultation; "*strategic (large bespoke projects or network-wide programmes of smaller upgrades) or anticipatory (ahead of uncertain need)*". We use this terminology primarily in the context of load-related investment. We believe that the regulatory treatment of both anticipatory and strategic investment (as characterised here) requires some refinement. We commissioned NERA to look at these issues in a report last year¹⁵ on the right regulatory treatment of strategic investment, which concluded:

- As an alternative to modifying the existing cost assessment of Load Related Expenditure (LRE), Ofgem could assess strategic reinforcement separately from totex.
- Future comparative benchmarking exercises should assess business plans based on a set of load growth assumptions that are consistent across DNOs.
- To incentivise efficient strategic investment, decisions to release funding via UMs should consider long-term, expected demands for network capacity, not just measurable current requirements.
- To attract efficient investment, Uncertainty Mechanisms (Ums) should also provide certainty at the point of investment for DNOs that the costs of strategic investments will be recoverable.
- Volume drivers reduce the asymmetric risk if they do not rely on ex post reviews of the efficiency of expenditure.
- Assessing strategic investments separately from business-as-usual schemes covered by demand metrics improves incentives for DNOs to invest efficiently.

We continue to support these conclusions, and the consultation's distinction between 'anticipatory' and 'strategic' will help categorise investments such that regulatory treatment can be easily understood and appropriately applied. In designing the detail of regulatory mechanisms pertaining to load, further subcategories will likely be needed to account for a wider range of investment types - for instance variations in the application

¹⁵ [Recommending Improvements in Regulation to Better Incentivise Strategic Investment in GB Electricity Networks](#) - NERA



of PCDs may be needed between strategic programmes of LV and HV works, and large new substations based on connection queues which are undergoing reform.

Using the definitions in 6.36 of the consultation, anticipatory investment should have agreed methodologies for classifying uncertainty and associated risk before proceeding, as with the ED2 Volume Driver which could be evolved for ED3. Strategic investment, as defined in the consultation, lends itself to high value project type regulation - existing mechanisms such as PCDs could be employed.

23. Should the price control provide more guidance or guardrails around the use of particular network solutions to achieve the ‘networks for net zero’ consumer outcome?

Guardrails around particular solutions would not be helpful. The DNO remains best placed to optimise across different drivers and optioneer effectively in terms of actual deployment of network solutions, which must be compliant with and supportive of discharging the wide range of DNO licence obligations regarding safety, design, and network outputs. There should also be sufficient flexibility in the regime to avoid stifling innovation - the application of novel approaches and technologies should not be precluded.

Guardrails in the sense of triggers for reviewing the use of a volume driver could be a useful tool, perhaps informed by findings of the RESP. These could be similar arrangements as the guardrails around the current load volume driver, wherein the rails are set at the high end of the credible range (and to avoid unnecessary regulatory burden), and the possibility to exceed the guardrails if regulatory review demonstrates there is a benefit.

A RESP role in this context could ease regulatory burden by setting clear expectations and criteria for use of the volume driver, allowing DNOs to use this mechanism with confidence and reassuring Ofgem that such usage was supportive of validated regional plans.

24. Should we consider how we might bring all network capex investment together within the framework, irrespective of driver (eg load, asset health, resilience), to ensure a common approach to future proofing and delivery?

This response must be read in conjunction with our responses to Q3, Q4, Q7, Q8 in section 1, and with our response to Q56 in section 5.

An optimised approach to Load and non-Load related expenditure is vitally important for a wide range of reasons, including to ensure a consistent approach to network resilience and to maximise efficiency of interventions on behalf of our consumers. We are confident that our current processes ensure the required optimisation between Load and non-Load investment programmes. We have found this in the context of our Hebrides and



Orkney Whole System Uncertainty Mechanism (HOWSUM) work, where an approach that considers multiple investment drivers whilst retaining a primary non-Load driver has allowed us to take a fully coordinated approach that maximises benefits to our communities and environmental aims.

However, we think Ofgem should be careful about making substantial changes to the regulatory framework for non-Load interventions, either by setting up a standalone ‘Plan and Deliver’ model for non-Load or by integrating non-Load and Load into a ‘Plan and Deliver’ model principally informed by RESP. As noted in our response to Q8, the principal value of the ‘Plan and Deliver’ model is in driving additional certainty of need and democratic accountability in the context of a net zero transition.

Our current processes mean that non-Load and Load investment programmes are optimised, avoiding inefficient duplication of work and ensuring Load requirements are considered during non-Load interventions and vice versa. Current processes enable a consistent approach to future proofing the network and addressing important resilience questions.



Part 3 - Responsible Business

25. How can we better strengthen accountability for consumer outcomes?

The RIIO-ED2 regulatory framework is already a robust framework through which Ofgem holds DNOs to account for a range of consumer outcomes. For instance, there are minimum levels of service DNOs need to provide customers, bespoke targets DNOs are required to hit to avoid penalties, extensive customer and stakeholder engagement that DNOs must undertake during the business planning process, and rigorous reporting requirements within price control to make sure DNO performance is well understood by the regulator and transparent. We consider the current framework to be working well however, Ofgem should consider publishing an annual summary or report of DNO performance to help customers and stakeholders get a better understanding of progress towards targets, and how the regulatory framework is working.

In the context of the overarching regulatory archetypes debate, as outlined in our responses to Q3 – Q9, we think Ofgem should first look at how existing tools in the regulatory toolkit could be used to hold DNOs to account for delivery of their ED3 Business Plans, including how they deliver on predefined consumer outcomes, rather than reaching for a potentially very restrictive ‘Plan and Deliver’ regulatory model at ED3. New tools should only be developed where there is evidence that current tools don’t work or can’t be evolved.

An important prior question to what measures can be taken to strengthen accountability for consumer outcomes is regarding the consumer outcomes themselves, and how best to view them. We agree with the consultation’s emphasis on the social purpose that networks fulfil in society – the regulatory framework needs to protect current and future customers. As per our response to Q2, we think it is imperative that Ofgem take an intergenerational approach at ED3 and consider how regulatory decisions taken today will impact current and future generations. This is an important consideration for the efficiency of the net zero transition at Distribution – Ofgem should minimise overall system costs of reaching net zero rather than prioritising short-term cost reductions that increase long-term costs. Therefore, consumer outcomes at ED3 should encompass the interests of current and future generations of energy bill payers. Linked to this, they should be calibrated to capture the full range of ways networks provide societal value to consumers – e.g. environmental benefits such as avoided carbon emissions or air pollution and enabling affordable housing to go ahead.

Ultimately, the framework should hold DNOs to account for intergenerational consumer outcomes that are informed by a holistic (rather than narrow) view of the value networks provide consumers. This links with our position on how the CBA methodology should evolve for ED3 to take account of wider factors like the economic cost of delayed connections or environmental benefits – see our response to Q41 and Q42.



26. What are your views on ED company reporting and the overall transparency of performance and compliance?

In line with our response to RIIO-3 SSMD, we think current reporting standards are rigorous which is important for ensuring the regulator maintains an accurate picture of DNO performance. We have multiple checks and quality controls in place to ensure that information and data including in regulatory reporting is accurate and in compliance with the license condition.

As per our response to the RIIO-3 SSMC, Ofgem should continue to look for opportunities to streamline and manage the overall regulatory burden for the benefit of both DNOs and the regulator. This is particularly important as we enter a period of rapid increase of network capacity where agility and flexibility will be key to delivery. Before introducing new reporting requirements, Ofgem should consider if the anticipated value-added warrants the additional regulatory burden – for example when it comes to adding more audits and inspections to increase regulator confidence of asset data, it would be useful to understand what additional assurance Ofgem is looking for – we would welcome a conversation about the additional regulatory work this might entail and how to streamline.

As per our response to Q56, where we reflect on the importance of a reporting framework that can capture the multiple benefits flowing from one investment, there is a need to improve the current reporting framework which focusses on a ‘One Investment, One Driver’ approach. An approach that is able to capture multiple benefits of one intervention, rather than these being unaccounted for, would enable Ofgem to better hold DNOs to account on their actual progress towards set targets. Evolving the reporting framework towards a ‘Primary Driver, Multiple Benefits’ approach would enable DNOs to make strategic investments that maximise efficiencies by optimising delivery from a totex perspective. For example, where anticipatory investment is the most efficient option but comes with a deferred measurable output, the current linear relationship between cost and outputs doesn’t incentivise this method of network investment and we need a reporting framework that takes multiple benefits into account.

27. Do you consider that ISGs alone are sufficient to ensure high quality and effective consumer and stakeholder engagement throughout the ED3 price control? What alternative or complementary approaches should we consider

We support the proposal that Independent Stakeholder Groups (ISGs) should be an integral part of effective stakeholder engagement throughout the business planning period and beyond. ISGs provide a vital mechanism for holding DNOs accountable and offer valuable feedback on plans – however, it is important that they should be transparently connected to regulatory determinations. During our business planning for ED2, we carried out significant stakeholder and consumer engagement to shape our



business plan - however it was not clear to what extent stakeholder views were incorporated into Ofgem's decision making. For ED3, Ofgem must clearly explain and show how its decision-making framework will align with the stakeholder engagement process DNOs will undertake.

It is also worth highlighting that our stakeholder engagement already goes far beyond what is mandated in the regulatory framework for the purposes of business planning. We routinely engage with a broad range of stakeholders, covering over 50 stakeholder segments. This ensures we continue to engage effectively with them through a multi-layered strategy that incorporates diversity and deploys effective research techniques. This ensures the diverse perspectives of our stakeholders are maintained at the centre of our business processes as business-as-usual, not merely when writing our Business Plan.

Since 2016, we have welcomed the views and challenges of an independent, strategic, stakeholder group in our business. Previously known as our Stakeholder Advisory Panel, our overarching stakeholder forum (re-named as the 'Powering Customers to Net Zero' group) holds us to account for both what we deliver as a business and the way in which we deliver it. The work of *Powering Customers to Net Zero* is complemented by two further stakeholder groups, our DSO Advisory Board and our Inclusive Service Panel. Both run with independent Chairs and members and hold us to account in a similar way, but are narrower in focus based on each of their specialist areas of DSO and consumer vulnerability.

An excellent example of our stakeholder engagement in a 'Business as Usual' (i.e. non-Business Plan) context is our Strategic Development Plan engagement strategy, designed to both demonstrate how stakeholder insights shape our network investment plans and capture further feedback to ensure alignment with local needs. Annually, we consult on 38 spatial strategies across our licence areas, engaging stakeholders through tailored communication channels and a public-facing guide based on nine stakeholder personas. To ensure their input is valued and acted upon, we use the Reach, Impact, Confidence and Effort (RICE) methodology to prioritize feedback consistently and transparently, publishing strategies that reflect changes influenced by stakeholder contributions.

We support the decision to discontinue open hearings, which, while useful, are less impactful than the expanded role ISGs can play in critique and challenge. Nonetheless, it is crucial to ensure transparency in how ISG feedback informs final determinations. As we refine our engagement approach for ED3, we are considering the evolving role of ISGs within a broader framework designed to ensure robust and effective stakeholder input.



28. Do you agree that Ofgem should adopt research approaches, such as deliberative techniques to ensure that the consumer voice is heard and considered throughout the ED3 and company Business Plan process?

We agree that a balanced approach to stakeholder and consumer engagement, incorporating a range of research methods, is needed to ensure that diverse consumer and societal needs are represented in the ED3 and business planning process. Quantitative research can overlook complex or varied perspectives, making qualitative techniques a valuable complement. Since ED2, we have adopted an inclusive service design methodology when developing our customer services, supported by external experts, which incorporates Human Centred Research and Design principles. This approach emphasises understanding consumer behaviour and broader societal needs, rather than solely relying on traditionally transactional customer feedback or quantitative surveys.

Clear and early guidance from Ofgem on the scale, methods, values and evaluation of any additional research requirements as part of the business planning process is essential. This will help to ensure clear comparability between each DNO business plan in key areas. Regarding additional deliberative research in particular, any approach that does not involve groups being convened by Ofgem at a national level should consider stakeholder fatigue, particularly as RESP processes are set up.

More broadly, and as above, our challenge to Ofgem is to make it clear how the output from extensive stakeholder engagement DNOs will undertake as part of their RIIO-ED3 planning process will shape Ofgem's decision making. For example, Ofgem could help model clear roles and responsibilities for national, regional and local spatial and network planning to ensure the top-down approach meets the bottom up seamlessly with NESO and DNOs working collaboratively to achieve this with minimal duplication.

29. How should our approach to enhanced stakeholder engagement be adapted to better include the perspectives of all vulnerable customers, including those that are seldom heard, digitally disengaged/excluded and those that are worst served?

As noted in our response to Q27, SSEN Distribution already engages with representatives of vulnerable customers through enduring panels, such as *Powering Customers to Net Zero* and our Inclusive Service Panel, as well as maintaining a strong network of partnerships with organisations including Citizens Advice, National Energy Action, Energy Action Scotland, Citizens Advice Scotland, Warm Works and Consumer Scotland, which can effectively represent consumer interests. While direct engagement with vulnerable customers is an important component of our strategy, it does present challenges. During ED2, for instance, we conducted a citizen's jury to explore issues like financeability and sustainability. This involved an immersive session on the principles



behind these issues, and how this should shape SSEN Distribution policy. This model could be considered for addressing specific issues in ED3.

In addition, our use of Human Centred Research to engage our customers (for instance in the development of our *Power Track* service) provides a clear framework for addressing the challenge of engaging vulnerable and seldom-heard customers. Many of these communities are unlikely to participate in traditional engagement activities, so it is critical to tailor engagement methods to their preferences. This principle underscores the importance of taking engagement to customers in their own context, rather than expecting them to adapt to our processes.

We would welcome clear guidance from Ofgem early on regarding the composition of ISG panels to ensure they reflect the diverse needs and perspectives of vulnerable groups. Ensuring representation from hard-to-reach groups, such as youth or digitally excluded individuals, in ISG panels would also enhance inclusivity.

30. What alternative or additional approaches might we use to ensure that the consumer voice remains central to our policy setting process?

We think the current stakeholder engagement requirements are robust and ensure the consumer voice is central as DNO Business Plans come together. In ED3, with the implementation of RESP which will set up separate forums for formal stakeholder engagement, as flagged above, there is a real risk of duplication and stakeholder fatigue.

To reduce this risk, we would welcome Ofgem seeking opportunities to encourage collaboration where possible between DNOs, taking advantage of the fact that most consumer-based research findings are likely to be consistent across DNOs with variations arising mostly from consumer segmentation. For example, differences in communication preferences or digital maturity are more likely to be driven by demographic factors, such as age or socio-economic status, than by license area. Regional differences in consumer preference and need, often driven by the unique characteristics of the network serving them, do exist across our communities – however, encouraging collaboration between DNOs and Ofgem, for instance on research approaches, would ensure consistency and comparability while allowing for bespoke adaptations as needed. A collaborative and well-structured approach will help maintain the centrality of the consumer voice in policy-setting processes.

31. Has the BMCS incentive served its purpose in driving performance improvements and how can we adapt the metrics to better incentivise performance across a wider range of interactions between DNOs and their customers, particularly relating to connections?

We provide responses to Ofgem’s questions on incentives under Q31-Q39.



We think the time is right to evolve or even replace the Broad Measure of Customer Satisfaction (BMCS); whilst it has served to focus DNOs on improving customer service, its mechanisms could be improved – or changed – to the benefit of our customers.

Customer Satisfaction Survey (CCS)

We agree that the CCS has successfully driven customer service performance improvements throughout ED1 and into ED2, clearly driving up customer satisfaction across the industry. DNOs have adopted a positive culture around customer service, and at SSEN, we have utilised the incentives to re-invest incentive rewards back into improving services further. We think it is important Ofgem retain some form of customer service-based incentive to continue to incentivise DNOs to deliver customer-centric priorities, which is especially important as societal electrification continues to accelerate.

However, there is a clear need to evolve or even replace the CSS which we do not think will remain fit for purpose in its current form given customers' evolving expectations of the service DNOs provide. The BMCS and CSS focuses on transactional activities that increasingly do not capture what our customers actually expect in terms of service and encourages micromanagement of processes that form part of the Broad Measure question set. We think Ofgem should consider other approaches to how we measure customer satisfaction, and more broadly elements like trust and the relationships built with customers.

We therefore suggest that other approaches are considered and targets re-benchmarked against a new approach if deemed appropriate. Although BMCS and CCS has driven up customer satisfaction, the scores DNOs achieve under the current methodology are not realistically comparable with other industries that customers engage in. For example, a 90% customer satisfaction score would place DNOs as the best performing sector in the UK if comparable to the UK Customer Satisfaction Index. In the context of improving scores, Ofgem need to look beyond simply tightening targets. Having a methodology that enables a cross-sector comparison would be more robust and allow DNOs to better understand how they well they are meeting customer expectations and needs against others. In a period where retaining customer trust and confidence is key, a robust customer satisfaction framework is key.

The BMCS model does not currently consider factors like trust, relationship management and societal impact, all key factors customers consider as part of their overall perception of a brand or industry. Furthermore, the BMCS approach is fixed on specific service types, meaning that as our services grow, and evolve, it makes it difficult to maintain a fair representation of our customers' satisfaction.



It is too early at this stage to recommend a single approach or regulatory option for evolution or replacement of the BMCS. However, a pragmatic next step could be a sector-wide working group, with Ofgem involvement, to review alternative approaches that would lead to a more robust measure of customer satisfaction. Considering an alternative approach could allow us as a sector to compare our performance with other, more similar sectors and improve trust across the UK in the DNO, energy and utilities sectors.

Complaints

We also query whether the current Complaints Incentive (CI) ensures sufficient focus on the resolution journey for a customer. Measuring on resolution rates alone does not necessarily mean that customers are satisfied with their resolution. In addition, classification of a complaint under the current framework is vague, leading to significant differences in complaints volumes across DNOs due to differing interpretations. A good evolution to the CI could be that customers are able to measure their satisfaction with resolution, and a clear definition of what DNOs should consider a complaint to be is given.

Next steps

In summary, SSEN would welcome a DNO led working group into how incentivising good customer satisfaction can be recalibrated in the regulatory framework, either through a reformed BMCS or through development of an alternative incentive. This should be evidence and research led, not opinion based. Changes should also be made to the CI.

32. How should the CVI be adapted for ED3 and should we consider greater alignment with the GD sector?

Whilst we strongly agree with the CVI's overall ambition to incentivise high-quality support for vulnerable customers, we believe it – as currently structured - could have unintended consequences.

PSR Reach

A risk of focusing on PSR Reach is that takes focus away the support we provide to our most vulnerable customers. Whilst there is real value in growing PSR awareness and numbers registered, especially in a context where awareness was low, there may come a point where Ofgem want to refocus attention on to the service of the support we provide those most in need. Whilst we stand behind the excellent service we provide our vulnerable customers, the regulatory framework needs to balance incentivising driving PSR Reach and quality of support provided. In addition, some form of segmentation to the PSR might be a useful tool to make sure the most vulnerable get the highest level of service. This might offer a way to ensure the most efficient allocation of our resources.

We are also supportive of the aims behind Department for Business and Trade's consultation on a universal register or data-sharing approach, which could redefine PSR



management and enhance the ability to address vulnerable customer needs through improved collaboration between sectors.

Value of Fuel Poverty Services or Low Carbon Solutions Delivered

While this element encourages support for customers in fuel poverty or low-carbon transitions, it again risks promoting a ‘numbers game’ rather than driving quality outcomes. By focusing on meeting numeric targets, there is a risk of overlooking the depth and effectiveness of the support provided. We recommend refining the approach to balance both quantitative targets and qualitative outcomes, ensuring that customers receive meaningful and impactful assistance.

Average Customer Satisfaction for Customers Who Receive Fuel Poverty Services and Low Carbon Transition Support Services

For customers receiving fuel poverty services, we have gathered moderate data to measure our performance, which has been insightful. However, gathering equivalent data for customers receiving LCT support services has been more challenging, providing less actionable insight. This reflects the difficulty in identifying and directly supporting this customer base, particularly since DNOs are not typically the first point of contact for vulnerable customers requiring LCT support. While we agree with the intent of this element, we believe the approach could be refined for better results. This may require further research and development. For example, an alternative approach could involve establishing a UK-wide independent support provider with associated funding to deliver LCT support services on behalf of DNOs. In this model, DNOs would provide the necessary technical and network expertise, enabling more consistent and scalable support.

Guaranteed Standards (GS) for PSR Customers

We acknowledge the potential for a GS to be introduced for PSR customers. While this may help prioritise efforts for these customers, we believe the current GS arrangements for interruptions are sufficient. Unlike GDNs, sourcing alternatives for services like heating and cooking during power outages is particularly challenging without generation. While such provisions exist for critical situations, scaling this service across the entire PSR population would not be cost-effective and would likely result in increased costs for customers.

Clarifying the Role of DNOs in Supporting Vulnerable Customers

We would also welcome greater clarity on the specific role of DNOs in supporting vulnerable customers. Currently, DNOs often act as a support provider of last resort when other sectors fail to provide adequate services. This reactive role creates challenges, including inconsistent service delivery and difficulty in addressing needs effectively. Establishing clearer boundaries would help ensure more focused and sustainable support while enabling DNOs to concentrate on delivering value within their core expertise.



33. Should DNOs have a role in delivering energy efficiency measures to homes and businesses? What might the scope of these services be and how should they be funded?

In the context of widespread electrification of heat, there is clearly a need to focus on energy efficiency measures to improve outcomes for consumers. The consultation correctly identifies a key benefit as reduced demand on networks. However, we do not think DNOs should take on responsibility for delivering national energy efficiency schemes, lacking both the experience and expertise to do so. Ofgem should also be wary of assigning DNOs a new responsibility that requires the development of new capabilities and expertise, particularly when they are placing renewed emphasis on the rapid delivery of network capacity during the RIIO-ED3 price control.

Additionally, Ofgem should consider that the cost of energy efficiency schemes would be indiscriminately passed through to energy bill payers while, depending on the scheme in question, disproportionately benefiting those able to afford LCTs.

We think overall responsibility would be most effectively instigated and coordinated at a national level by central Government. This will require the participation of a number of industry actors, including suppliers, heat pump providers and energy efficiency installers to facilitate effective roll out of energy efficiency programmes – in this context, DNOs have a convening role to play and already contribute. The LENZA tool created by SSEN is already being used by Local Authorities to formulate and their Local Area Energy Plans or Local Heat and Energy Efficiency Strategies. In addition, the NeRDA portal is providing millions of near real-time data points to allow users to understand the usage of the network, which could provide valuable insights into exactly where local energy efficiency schemes could improve energy constrained offers.

Through innovation, we are supporting efforts to improve efficiency and deliver network benefits for the energy transition. For example, our EqualLCT project will explore how to unlock private investment in energy efficiency and heat pump installation by identifying and valuing long-term network benefits of peak heat demand reduction. It will create scalable business models that allow the DNO to contribute to the installation of energy efficiency measures in areas where it provides a benefit to the network. This could complement national programmes. The enhancement of tools like LENZA will allow data to be made available to LCT supply chains to help the targeting of propositions. Similarly, the VIVID project harnessed existing data to identify and support vulnerable households, helping them access timely financial and practical assistance, which included energy efficiency interventions.

34. How can we drive further service improvements under the TTC incentive?

We agree that the TTC has been effective in driving a higher quality service provision for new connections. However, we believe that RIIO-ED3 presents an opportunity for Ofgem



and industry to assess whether it is still fit for purpose in a price control where meeting customers' expectations on timescales is more important than being measured on speed of delivery.

Especially in cases of complex connection requests, with the framework as it is currently designed, at times we have to strike a balance between truly great service and timeliness due to the penalties associated with the TTC incentive. In these complex cases, trying to achieve our TTQ targets does not always work in the customers best interests. Where a customer submits the minimal information required for us to start the clock, it can be a challenge for us to make contact with the customer to ensure the quotation they are provided fully meets their expectations. This may lead to rework and changes to costs, potentially impacting our overall performance for customer service under BMCS. Whilst we believe the simplicity of some of these applications means good TTQ and customer service is achievable, there are complex minor connections projects that need customer interaction to ensure more accurate designs and costs.

With regards to post acceptance TTC, a change to a 'site ready' approach may be more appropriate if Ofgem are of the view that this should continue to be an incentivised metric in RIIO-ED3. This would allow a true metric of how DNOs can respond to customers when they are ready for their minor connection to be completed. We see a large portion of our applicants that are not ready for works to commence once they have accepted their offer, at times this can be 6-12months from construction. Allowing for delays outside of the DNO controls will also allow a truer reflection of performance.

35. Should the TTC also apply to domestic connection upgrades i.e. fuse/cutout/service cable upgrades, including unlooping?

Whilst we do not disagree that customers of this type should be provided a similar level of service to those making typical minor connections applications, Ofgem need to consider the additional complexities to these types of applications where unlooping is required between multiple properties.

We regularly experience situations where the neighbouring looped customer (who is not making the application to connect LCTs) refuse access to their property to either disconnect the existing looped supply or to connect a new unlooped supply.

Although on occasion, access difficulties can be mitigated through negotiation, it is not uncommon for access to be completely refused and load limiting devices are then required not only on an interim basis but possibly on an enduring basis. Therefore, any expanded incentive would need to be able to take account for access issues which are outside of DNOs control and have a very clear stop clock.



Further, we are aware that some DNOs have embarked on large programmes of proactive service unlooping (funded by customers). Any incentive targets would need to reflect the extent that DNOs had already been funded for some of this work proactively.

As with any new incentive, we would stress that there needs to be sufficient time to gather data and ensure it is comparable across DNOs.

36. What is the best approach towards incentivising services to major connections customers and how should the MCI be adapted for ED3?

After only 1 year of the current Major Connections Incentive (MCI) framework, it is likely too early to suggest that this does or does not need to be adapted for RIIO-ED3. It is important that Ofgem ensure any fundamental reforms to the MCI fully consider the impacts on costs to both connecting customers and DUoS paying customers. Timeliness of connections metrics at major connections, if to be considered, must factor in the large scope differences between projects that fall within the same market segments, the impacts of Transmission delays, and other complexities that are outside the control of the DNO.

With the current level of reform within Connections, it is prudent to consider the outputs from the Connections incentive review with all industry to ensure that they do not create potential conflicting frameworks similar to those we have in Minor Connections currently.

37. How should the ED3 framework adapt to ensure that customers connecting to the distribution network are provided with the service that they need from the DNOs?

We consider it is worth breaking out this question between minor and major connections as the service customers are looking for is slightly different between the two.

Our **major connections** customers tell us that they value:

- Readily accessible and up to date granular network data to assess opportunities for connection.
- Quality upfront engagement ideally with system planners to validate their assessment of where there are opportunities to connect.
- An accurate upfront quote.
- Early view of the delivery plan.
- Ongoing engagement around that delivery plan to adapt it around changing circumstances from both the customers and DNO perspective.

The current regulatory framework covers some of these indirectly through the Major Connections Incentive (accuracy of quote and delivery experience), while the DSO incentive would partially cover quality of information published.



We consider that the main development for ED3 would be to make these aspects more explicit within the regulatory framework. This could include standardisation of formats for information published and measured KPIs around producing a delivery plan on the agreed date. There is a strong read across here to Ofgem's end to end connections review.

For **minor connections**, our customers place greater emphasis on the ease of process in making an application, the support they receive through that process and timeliness of quote and delivery. We consider these aspects are well covered in the regulatory framework through Time to Connect / Time to Quote (TTC/TTQ) and the Broad Measure of Customer Satisfaction (BMCS). As highlighted earlier, we need to recognise the natural tension across those two incentives (speed vs service) and believe that we have reached a point where it becomes challenging to further improve performance in one, without offsetting performance in the other.

Finally, we would highlight that the reporting arrangements around connections are one of the more complex in the current price control. It involves recognising the competition element (where we need to capture margin for every project where we do not pass the competition test), a range of different timescales for activities across different market segments which we need to report against under Guaranteed Standards of Performance (GSOP) and increasingly, data on the connections queue and timescales for delivering larger projects. Regulatory reporting regarding connection takes considerable resource (which could be better deployed on activities which directly support the customer) and makes the processes within connections complex. As acknowledged by Ofgem's end to end connections review, we consider that there is merit in reviewing some of these requirements which have been layered on top of each other over multiple price controls. Consequently, we'd be supportive of exploring a consolidation of reporting requirements with Ofgem and other DNOs.

38. In the context of greater electrification, is our current approach towards regulating reliability appropriate for ED3?

For ease, we have combined our answer to Q38 with Q59, on the approach to reliability in the context of the increasing impact of climate change on our network.

The societal shift to electrification and the growing challenge of climate change fundamentally changes the context of electricity network reliability, and this needs to be reflected in the regulatory framework – we think the time is right to rethink the current approach.

For our customers, network reliability is one of the most important aspects of our performance. Its importance will only increase as dependency on our network deepens with the continued electrification of heat and transport, and as more embedded generation connects to our networks. Societal electrification and deeper dependency



will drive several factors of change at ED3. First, our customers' expectation of our service is evolving, with network reliability and resilience likely to be even more important to them in the future. Second, the network is becoming more complex - with greater use of flexibility and more embedded generation – meaning customers may experience quality of supply issues they currently do not. Third, to meet greater demand, we will carry out more work on the network than ever before. This means more planned outages but also, inevitably, that we carry more reliability risk on parts of the network as works are carried out.

At the same time, we are now seeing the impacts of climate change become more frequent and more intense across our networks. This is not a trend that is limited to Distribution. The National Infrastructure Committee recently reported on the growing challenge climate change poses to UK infrastructure and the need for urgent attention from Government, regulators and effected sectors.¹⁶

In this changing context, it is imperative that any reliability incentive framework drives the right interventions in RIIO-ED3. It must not disproportionately penalize DNOs for carrying out the necessary interventions across the network, at the pace which will be needed in ED3. This links to the point we make in answer to Q4 and in our cover letter, about the importance of a holistic regulatory approach with all regulatory components working together in a harmonious way.

Any review of the reliability framework will need to consider its different components, which include the IIS, but also worst-served customers, GSOP and the interaction with the resilience framework. These different components must work together to ensure that the regulatory framework delivers the right outcomes for consumers, at the right cost.

Reviewing the Interruptions Incentive Scheme

Since its introduction over 20 years ago, the IIS has been successful in driving significant reliability improvements across DNOs. The societal shift to electrification and the growing challenge of climate change fundamentally changes the context of electricity network reliability compared to when the IIS was introduced, and this needs to be reflected in the regulatory framework. The cost of delivering reliability improvements in 2025 is far greater than equivalent improvements in 2005, and we think the time is right for a fundamental review of the IIS.

Any review of the reliability framework will need to consider the overall framework as noted above. This could include an overhaul of the IIS, but should consider at a minimum the following:

¹⁶ [Developing resilience standards in UK infrastructure](#) – National Infrastructure Commission



- **Providing clarity on how improvements in reliability should be funded**, to meet baseline targets: in RIIO-ED2, Ofgem set a clear design principle which stated that *“the delivery of a target level of outputs [...] should be funded through baseline allowances, rather than through incentives. Target levels should be set so that the benefit to consumers of achieving target levels is broadly balanced by the cost in higher network charges.”* Ofgem must be clear for RIIO-ED3 that the same principle applies, and ensure it is applied consistently across IIS and other incentives.
- **Ensuring the IIS framework is fit for purpose for a period of high-capacity growth.** A pragmatic approach is needed, cognizant of the fact that ED3 will entail far more interventions on the network than before, meaning more reliability risk will need to be taken as part of planned outages. The IIS framework needs to ensure DNOs are not disproportionately penalised for doing the right thing whilst still effectively managing network risk and maintaining supply. This may entail testing the category of Planned Interruptions to make sure it drives the intended behaviours from DNOs at ED3. We must also ensure that any adjustment to CI targets considers the current arrangements that DNOs currently face with the impact of the Covid years in the outturn in ED2.
- **Testing if the physical characteristics of licence areas are properly accounted for when IIS targets are set.** Our SHEPD licence area covers 25% of the UK land mass but is the most sparsely populated Distribution region in the UK (we have approximately 14 customers per km², the national average is approximately 133 per km²). It includes 59 remote island communities who are supplied and interconnected through submarine cables. Serving such remote communities across such a large area creates specific challenges in terms of storm response and meeting CI and CML targets – and these will only get worse as climate change continues to exacerbate weather events. Our teams already sometimes struggle to get to remote islands to fix faults, having to rely on one ferry provider. Ofgem’s CI and CML targets and the improvement factors must reflect the various differences between DNOs and the external factors influencing performance so that the IIS framework is properly optimised to the specific challenges license areas face.
- **Reviewing the definition of exceptional event:** In 2023/24, we had 47 days in our SEPD license area with at least twice the daily average number of faults. This compares with 29 equivalent days in the last 4 years of RIIO-ED1. These 47 days did not meet the Exceptional Event threshold under the current IIS framework but would have done in previous price controls. In addition, between October 2023 and January 2024, we had six named storms which



caused a range of issues across the network including flooding at sites that had not previously been identified as being at risk. Both examples highlight a growing trend of adverse weather where our network is severely impacted, despite our investment programme to improve network reliability over time. To underline this point, a storm of the same intensity now causes fewer faults than it would in the past because of reliability improvements. Raising the threshold of what counts as an exceptional weather event over time, coupled with the impact of climate change which causes more severe weather disruption, means the reliability improvement needed to meet targets and avoid penalty is greater than ever before. We think, as currently set, the framework leads to disproportionate penalties.

- **Ensuring targets do not overly rely on historic climate data** which increasingly does not give reliable insights into the challenges our networks will face in the short-term. For example, we are seeing increasing volumes of underground faults resulting from saturated ground due to prolonged summer rainfall. The default approach in the regulatory framework is that underground faults cannot be storm related, and therefore no exemptions are provided. What we have seen is the result of prolonged abnormal conditions which, on each day may be considered ‘normal’, but have a cumulative effect on our assets and cannot be predicted (as they are often caused by ground movement once the earth becomes saturated). We are concerned that a continued reliance on historical data to set targets and inform the regulatory approach is leading to disproportionate penalties. It is also leading to a mechanism which is not adapting to the scenarios DNOs are facing today and will continue to face in the future.

This review should be conducted before the start of ED3, potentially as part of the Sector Specific Methodology Consultation (SSMC). It will be fundamental to ensuring DNOs are proportionately incentivised to provide a reliable service to customers.

It should be informed by the wider **review of the Value of Lost Load (VoLL)**. This review needs to ensure the regulatory framework reflects the importance customers place on network reliability. However, it is important that the wider context of electrification and climate change is considered when carrying out the VoLL review. Potentially tighter IIS targets combined with a higher VoLL, which could lead to a much stronger incentive rate, could mean a more severe penalty for DNOs missing targets potentially for reasons outside of their control. For instance, Ofgem should be mindful to avoid a situation where a DNO needs to balance the risk of a large penalty against carrying out accelerated and widespread works to prepare the network for net zero (given the fact that as work is carried out on the network, because power is often moved to a ‘back-up’ circuit to enable works to take place, there is an inherent reliability risk involved especially where the



volumes of circuit outages at any one time is increased). This consideration has parallels to the position and work being undertaken by NESO, TOs and DNOs considering overall system benefits, constraint costs and system risk. If the reliability framework has the unintended consequence of preventing required works being undertaken, this would not be in the interests of customers. Therefore, the VoLL review needs to carefully balance a potentially higher VoLL with any approach to target setting to ensure the framework avoids creating a situation where we are disproportionately penalised for outages (planned or unplanned).

Worst Served Customers

In a similar vein, we think the Worst Served Customers framework warrants a review. As currently structured, it can create perverse outcomes where it is simply economically unviable to intervene to improve the service of some of our worst served customers. This is especially the case in our SHEPD licence area. The current regulatory framework makes some attempt to correct this through the North of Scotland Resilience (NoSR) mechanism. This mechanism is specifically designed to fund improvements to those areas that suffer poor performance, but where the cost of improvement can be extensive. A good example is a long radial network that connects only 500 customers, typical of some of the remote areas of our SHEPD network. They could all be worst served customers under the current framework, however, under the incentives as currently set, it is economically inefficient to intervene and improve their reliability. There is a strong case that the NoSR fund needs to be increased. If left unchanged, the WSC framework could lead to a significant reliability performance gap between groups of customers in the same licence area. This could become more problematic as dependency on the network deepens in ED3, and customer expectations continue to evolve. Ofgem could look at a tiered system for Worst Served Customers which could differentiate between different levels of service being provided – the current approach is quite blunt and may not drive the right investment decisions for our customers.

Guaranteed Standards of Performance

More persistent and severe weather also affects our GSOP performance with more customers off supply. With shorter times to restore people (12 hours in normal weather, assuming the weather does not become an exceptional event), it means it is harder for us to get everyone back on supply in time, therefore we have more failures.

That is particularly true in SHEPD, where the geography means that simply getting to customers in time can be a challenge. This is most extreme in Shetland, where there is only one ferry operator - if that service isn't running, we cannot get to those customers to restore their power. Since that is beyond our control, we think the islands exemption for IIS and GSOP should be re-introduced, ensuring it only applies where our physical access to the network is prevented and there is no other way to restore supplies. We note



that this would bring the framework in line with comparable performance regimes in other sectors (e.g. Rail) – and Ofgem already make some provisions along similar lines when access is prevented in other ways (e.g. flooded roads).

Short Interruptions

In RIIO-ED2, Ofgem considered introducing a new incentive on short interruptions. We note that Ofgem does not appear to be considering this for RIIO-ED3. Any new incentive would require a robust evidence base including an understanding of impact on customers, an assessment of willingness to pay and any interactions with the existing IIS targets. There will also be a need to ensure severe-weather related performance is adequately accounted for in any targets for performance.

Other points

We would welcome an approach that is able to respond to events on the ground in a more flexible way. For example, if a DNO suffers three flooding events at substations which had not previously been judged to be at risk of flooding, this could trigger access to funding for a review of similar substations to consider increased protection. This would give DNOs greater ability to respond to risks as they materialize, and ensure customers are not exposed until the next price control.

There is also a link between climate change and workforce resilience - we are already seeing the effects of fatigue on teams responding to successive storms in quick succession. In ED3, this may serve to exacerbate existing workforce resilience challenges.

Lastly, Ofgem should consider the role of nature-based solutions when it comes to actively building network resilience to climate change and delivering reliability improvements. If standard asset specifications are required to consider nature-based solutions like sustainable urban drainage systems (SUDS) and bioswales then mitigation is built in from the start. Consideration beyond individual asset level is required too. If catchment-based approaches become a resilience investment option then multiple assets can be protected downstream of an intervention, costs can be shared as a result of shared investment from multiple beneficiary sectors, customers' money goes further, and multiple benefits are delivered back to society.

39. What role should bespoke outputs and CVPs have in ED3?

We successfully secured two CVPs in RIIO-ED2 for which we received a reward under the Business Plan Incentive. While we believe that our CVPs are already driving benefits to our customers and society, and demonstrating leadership, the process of developing CVPs was time consuming, and would have benefited from greater clarity on the kinds of activities Ofgem would like to see rewarded in this way.



Aside from CVPs, we are very clear that bespoke outputs should be retained as an option, in particular considering network specific characteristics and features e.g. the extremely remote nature of our SHEPD licence area, including islands that are hard to reach (like the Shetland Islands).

More generally, Ofgem should consider other ways in which they could drive ambition and reward proposals that go beyond baseline expectations. This should include through the design of the Business Plan Incentive. We understand concerns from some stakeholders around a ‘postcode lottery’ but this needs to be balanced against allowing the opportunity to develop and implement ambitious proposals that would drive genuine benefits. Ofgem can use the Business Plan Guidance and design a regulatory framework at the next price control to ensure successful proposals are embedded in the framework and funded through the price control. The price control timelines do not allow sufficient time for individual proposals to be assessed by Ofgem, tested with stakeholders and costed into other DNO business plans.

40. How can we optimise late and early competition models for application in electricity distribution?

Competition already plays an important role in the context of electricity Distribution:

- **Native competition**, as it was referred to in RIIO-ED2, is fully embedded in our delivery model. We already competitively procure many of our services and we also have legal obligations regarding competitive tendering under the Utilities Contracts Regulations 2016 and the Utilities Contracts (Scotland) Regulations 2016. For example, in our SEPD region, we have signed agreements worth over £1bn with three contract partners, to support delivery of our RIIO-ED2 business plan commitments. We are currently in the process of rolling out a similar approach in our SHEPD region.
- We also already have **extensive competition in place in our connections business**, with sufficient levels of competition now deemed to exist in a number of connection project market segments such that the requirement for a regulated margin has been removed as true competition now exists.
- Finally, the **Independent Distribution Network Operator (IDNO)** and Independent Connections Provider (ICP) model is another example of competition in Distribution: our view is that this model requires urgent review to ensure that it is fit for purpose for net zero, and delivers value for consumers.

In the Distribution space, Ofgem’s focus should be on ensuring the regulatory framework supports delivery, as outlined in our responses to Q62 – Q65 on supply chain and workforce resilience. Ofgem must also prioritise a review of the IDNO framework.



Competition is of value to consumers only when realised in a way that avoids unnecessary complexity and enables the timely delivery of network projects, delivery of net zero and the protection of security of supply, reliability and safety. Any future expansion of competition models must not delay expansion of the network and tendering must create net benefits to consumers rather than net costs. Competition must only be implemented where there is evidence that there will be true value for consumers, supported by a robust impact assessment.

Much of the network expansion that is required at Distribution level will be on LV networks, which does not lend itself naturally to other forms of competition. For an activity to be suitable for competitive delivery, we consider it must be a new project that is large enough to be attractive to investors and is physically separable from existing networks. There must be multiple competitors in the market willing to bid for the work to ensure that consumers are truly seeing the benefits of competition. As part of our RII0-ED2 Business Plan, we carried out a thorough assessment of our proposed activities against Ofgem's criteria for competition, with no projects meeting all criteria at the time.

41. How should our approach to cost assessment evolve, to enable us to better manage increasingly pronounced trade-offs between consumer protection, efficiency and investment in the distribution network?

Overall, we support the need for cost assessment in the next price control. Once an archetype decision has been made by Ofgem, we welcome the opportunity to engage in developing the most effective cost assessment toolkit for ED3 while considering the nature of the delivery environment DNOs are currently facing.

We have used this opportunity to highlight some specific improvements we think could be made to the ED2 cost assessment toolkit which would make it more appropriate for ED3 as well as addressing some of the points Ofgem has included in the consultation.

Retaining a totex approach

Spend fungibility as a concept is incredibly important under an ex ante incentive regulation framework which relies on companies being incentivised to find the most cost effective and efficient ways to run their networks. Much like the cost assessment toolkit takes a top-down view for totex modelling to balance nuances across cost categories and interdependencies between cost drivers, DNOs need to have this view when making appropriate and efficient investment and expenditure decisions to optimise delivery. By reducing spend fungibility for BAU activities, Ofgem could disincentivize efficiency-seeking behaviours by creating trade-offs between cost categories and increase regulatory burden both when setting allowances and monitoring in period. It is important that DNOs have the flexibility and autonomy to deliver innovative and efficient solutions,



and we would therefore not agree that fungibility should be reduced under an incentive regulation archetype.

We also note that the Totex Incentive Mechanism, one of the key incentives in the ED2 framework, has not been mentioned in Ofgem's consultation. Our view is that it is an important tool to incentivise innovation and cost efficiency alongside spend fungibility and should be retained in any proposed framework. Similarly, we would like to raise that any potential Business Plan Incentive will need to be designed and consulted on early in the price control setting process. Clear and comprehensive Business Plan Guidance needs to be published early to enable optimal DNO performance, methodologically sound assessment by Ofgem and avoid a short-term 'race to the bottom' driven by an incentive for DNOs to minimise submitted costs. We cover this in more detail later in this question response and look forward to further engaging with Ofgem on the development of potential Business Plan Incentives.

As we have mentioned elsewhere in our response, we do see some potential merit in the 'Plan and Deliver' archetype where it relates to work that is in scope of the RESPs. While Ofgem's view is that reducing spend fungibility for outputs identified by RESPs could give greater confidence on behalf of consumers that outputs would be delivered, we do think that this issue is addressed by other tools within Ofgem's control such as PCDs, Use It or Use it Allowances (UIOLs) and volume drivers under the current ED2 framework. In this case, we could support expansion of the use these tools in an appropriate and proportionate way to guard against the risk of unjustified under delivery and inefficient underspends.

Under the proposal that RESPs form a role in identifying strategic need to inform DNO network investment, our view is that the interactions between the following areas will need to be refined:

- the identification of strategic need for investment from RESPs as proposed
- the optioneering after need is identified, which we consider sits best with DNOs
- the measurement and incentivisation of efficient output delivery

While we are of the view that technical cost assessment approaches, as proposed by Ofgem, could be thread through each of these steps, it is unclear how the cost and output relationship, relied upon to some extent in Load Related and Asset Replacement expenditure specifically, would apply to a holistic approach where individual investments may be tied to multiple outputs in DNO strategies.

Historically there has been a broadly linear relationship between inputs and outputs (for example Asset Replacement expenditure and NARMs) and it is unclear how this relationship would work under a scenario where RESPs identify strategic need which



leads to load-related investments that interact with cost drivers and deliver multiple benefits.

Our view is that holistic network planning and increased use of anticipatory investment in the load space as proposed is critical to delivering net zero efficiently. As one of the only DNOs currently trialing a multi-driver holistic network planning approach through the Hebrides and Orkney Whole System reopener, we do not think that all implications have been considered or accounted for as outlined above. This is something that we would welcome working with Ofgem on for ED3 if this approach goes ahead as proposed.

Suggested improvements to the ED2 cost assessment toolkit

We have assumed for the purpose of this response that the ED3 archetype will broadly align with the ED2 incentive framework as we consider it is fit for purpose if some developments are made. However, if any changes are made to the archetype for ED3 there would need to be a full review of the appropriateness of the ED2 cost assessment toolkit to enable the right decision-making, incentivise the right behaviours, and ensure the most efficient transition for net zero, as per the framework consultation's aim.

Though we agree that some form of cost assessment should take place in price control frameworks, the toolkit employed in ED2 has evolved to become a highly complex process that could benefit from simplification and consideration of the current delivery context.

Acknowledge the need for changing assessment methods

While we understand that the majority of a DNO's work mix is BAU/repeatable activities which are theoretically suited to benchmarking exercises, there are numerous areas where, given market constraints and economic volatility, we are seeing outturn costs that are significantly higher than the unit rates set by Ofgem in the ED2 Final Determinations. On this basis, we would welcome expansion of cost areas benchmarked only on forecast costs.

The current framework takes a short-term cost minimising approach, where DNOs are incentivized to deliver at the lowest cost. This can lead to a 'race to the bottom' in order to perform well on the Business Plan Incentive and outperform rates set by Ofgem in Final Determinations. We would welcome development of a cost assessment approach that takes a view on costs through a lens of optimising consumer outcome in the long run, not necessarily what achieves a short-term outcome at the lowest cost.

Use statistically robust cost drivers where benchmarks are needed

There are examples of drivers used in ED2 models that predict characteristics of networks rather than drivers of costs in each network (i.e. MEAV is a driver of network scale, not operating costs of said network and is not statistically robust in some



regressions). While we understand that it is difficult to model some DNO cost areas, we do not agree that a statistically insignificant driver should be used in lieu of robust metrics and we would welcome these discussions starting early in the price control setting process.

Set out cost assessment methodologies early

We are of the view that Ofgem should conduct pre-emptive modelling based on annual regulatory submissions to get an idea of the ED2 model fit against outturn. This would identify key areas where there are clear step-changes in costs compared to Ofgem ED2 unit rates and areas where inconsistencies in reporting are causing issue. Using this information at the outset to produce clear and considered Business Plan Guidance will enable the cost assessment process to run more efficiently and produce more accurate and balanced results. Ofgem should also ensure models are made available in a timely fashion at key points in the process, to enable a full response to consultations. This will also improve robustness.

Ensure company specific factors are accounted for appropriately

In ED2 our company specific factors for SHEPD were not fully accepted by Ofgem. This has led to SHEPD looking artificially inefficient, for example where Ofgem modelling excludes subsea cables from MEAV in some models but includes these costs in CAIs. There are multiple areas where Ofgem's non-acceptance of company specific and regional factors have driven apparent inefficiency and has meant that we are underfunded in some areas. In order to accurately benchmark business plans, it is imperative that Ofgem are comparing like-for-like and we welcome the opportunity to engage with Ofgem on this as early as possible.

Enable strategic and anticipatory investment

The current cost assessment and reporting framework is heavily interlinked with the delivery of outputs assigned to expenditure as we have already mentioned. While we agree that this is a significant cornerstone of the RIIO framework, there is a need to enable investments that have a future output (i.e. advanced ordering of plant to ensure solutions are ready at time of need rather than being delayed by supply chain constraints). This also ties into our comments regarding Strategic CBAs in Q42. The current delivery context will require investments where decisions need to be made not purely based on immediately realisable economic benefits at the time of delivery but also on more forward-looking CBA metrics to monetise other drivers of investment decisions.

Role of ex post cost assessment

Our view is that an increase in ex post assessment would require a significant change to how the relationship between Ofgem and DNOs currently operates. While we agree that



a move to ex post assessment, specifically for large network investment projects, could be beneficial in reducing time taken and some regulatory burden when paired with RESPs in lieu of needs cases, our concern is around the effect this could have to investor certainty. It could result in increased uncertainty for DNOs, increased uncertainty for investors, and therefore lead to a high cost of capital requirement to meet net zero targets.

There would be potential over time (i.e. multiple price control periods) for the relationship between Ofgem and DNOs to operate well in this way and for the trust to be built that DNOs can invest efficiently without risk of significant disallowance ex post, however in the current context we would question whether the industry has the time to test this out or build the supporting frameworks to allow it to be implemented effectively.

If Ofgem were to more seriously consider this option, it would be imperative that very clear obligations are placed on DNOs at the start of the price control and very clear mechanisms for cost disallowances are set out. For example, the DIWE framework where Ofgem would need to demonstrate through evidence that DNOs had exhibited any Demonstrable Inefficient or Wasteful Expenditure to make ex post disallowances.

42. How should our guidance for cost benefit analysis evolve to better enable optioneering between different interventions, taking relevant long-term risks and benefits into consideration?

We find that CBAs are a useful tool to demonstrate optioneering and decision making when there are multiple approaches or solutions that could achieve one output. We also acknowledge that progress has been made in recent years to standardise CBA submissions for comparison purposes while trying to ensure that the nuances of individual circumstances can be preserved and presented. With that in mind and acknowledging that it would be difficult to achieve a 'perfect' set of CBA templates and guidance applicable to all licensees in all sectors, we do think there are further improvements that could be made for ED3. We also note that Ofgem has asked this question directed to the CBA guidance, but our view is that the wider CBA toolkit (including guidance, templates and associated narratives and assessment) could benefit from improvement.

Considering the current CBA toolkit, there are some small changes that could be made to ensure this is more effective and reduces regulatory burden for both Ofgem and DNOs such as:

- Standardising assumptions and inputs (where possible and does not limit optioneering demonstration),
- Limiting scope of CBAs to enable fuller review (i.e. reduce number of options presented in full), and



- Limiting 'step backs' and redrafting of optioneering if CBA inputs change through agreement of a materiality threshold.

Taking a broader view, there is a requirement to consider that DNOs and licensees in other sectors are facing a very complex setting in which to make investment decisions as we progress towards net zero which may require some development to current approaches. The current template focusses on benefits that are more straightforward to monetise, however in the current context we need to be able to consider costs and benefits outside of economic reasoning to produce comprehensive optioneering and make the most efficient investment decisions. To address this, broader benefits need to be captured, i.e. enabling connections now and capturing environmental and societal benefits.

Our view is that the Strategic CBAs developed in conjunction with other industry bodies (see NERA report¹⁷) and drawn from Whole System CBA methodology solve some of these difficulties. The Strategic CBA has been developed to create a methodology for monetising benefits of investment that aren't currently captured in the CBAs from Ofgem and quantify the economic cost of networks not being ready for net zero. The template allows the optioneering process to present broader socioeconomic benefits of investment, which are increasingly necessary in order to future proof network investments now.

Our view is that these templates are a good starting point and as such we have piloted the approach on our Hebrides and Orkney Whole System reopener in order to arrive at the holistic whole-system solutions required in this area of the network. It has allowed us to consider options that take a forward-looking view of the network and ensure that current investments are efficient now and in the longer term by looking at all options to 2050 together including smaller interim interventions and longer term interventions together to optimise delivery. We will continue to pilot this approach going forward and would welcome further engagement with Ofgem to develop a tool that could be used cross-sectorally. More generally, we consider that the regulatory framework in RIIO-ED3 should evolve to consider more broadly the longer-term benefits to consumers and society of delivering investment. Our Strategic CBA is a step in this direction and we look forward to working with Ofgem on further developing the framework.

43. Do you agree that the current Real Price Effect (RPE) methodology should form the basis for adjusting allowances in ED3?

We think that it is important under an ex ante allowance framework that DNOs are not exposed to the risk of general market price changes over and above inflation. As we mentioned in our Strategic Commentary provided to Ofgem this year, the current ED2

¹⁷ [Recommending Improvements in Regulation to Better Incentivise Strategic Investment in GB Electricity Networks](#) - NERA



methodology is not reflective of external market conditions that are driving both general cost increases and changes to contract clauses to increase the level of cost risk and volatility that can be passed through to us. The relativity of the forecast index and the time at which it was set has meant that it did not take into account many of the drivers of increased costs that are being experienced now, for example increased market demand for specific plant exacerbating supply chain constraints, labour market constraints and geopolitical challenges among other things. All of this is affecting the real prices that we pay to deliver our obligated outputs. These increasing contract costs are also affecting our ED2 reopener submissions and we expect this situation is likely to continue and affect our ED3 submissions.

It has become very clear that the ED2 adjustment methodology is not fit for purpose in forecasting outturn. It is leading to varying allowances and revenue shortfalls throughout the price control which, if continued will affect investor certainty and our ability to commit to delivery contracts due to concerns around financeability and certainty of allowances. For this regulatory year the application of the current methodology has meant that DNOs have had an unexpected negative adjustment applied which assumes that DNO costs have increased less than CPIH even though it is clear from market activity that prices have in fact been rising. This has added significant uncertainty going forward into the rest of ED2, and concerns regarding forecasting inaccuracy and revenue volatility in an integral delivery period.

Our view is that it is imperative that significant improvements to the current RPE approach are made to address these issues and would welcome the opportunity to work through alternative approaches with Ofgem. As per our answer to Q9, this could involve any of a number of potential alternatives, from adjustments to indices used in deriving the ex ante allowance to developing an ex-post true up mechanism to provide any necessary cost adjustment corrections and smooth volatility in allowances.

44. Do you agree that the current approach to setting the ongoing efficiency challenge is a suitable starting point for ED3?

The combination of this year's RPE adjustment, ongoing efficiency and the glide path to the 85th percentile all effectively subject DNOs to multiple efficiency challenges at once. It is important that Ofgem reviews these measures in the round in advance of ED3 to ensure that DNO allowances are not being squeezed to the point of reducing output at a time when the stated outcomes of the price control are that it should be increasing significantly instead.

As we noted in our RIIO-3 SSMC response, our view is that the limitations in calculating the historically applied rate of ongoing efficiency should be acknowledged, with steps taken to rectify and ensure a more robust approach is taken going forward if at all. This would include the use of the most up-to-date productivity and market forecasts.



The application of ongoing efficiency also needs to be considered in the context of net zero. The growth in outputs in the sector means that DNOs are facing significant challenges in an environment of unprecedented cost pressure from multiple avenues and are expected to significantly ramp up delivery over the rest of ED2 and into ED3. The sector is not in the same position it was when setting ED1 or even ED2 objectives. With such a push for delivery at pace to meet Government targets and the expectations placed on DNOs as part of this, a judgement needs to be made as to whether it is still appropriate for Ofgem to expect DNOs to make ongoing efficiency savings, particularly in light of the other basket of mechanisms, including RPEs and upper quartile challenges.

In the context of RESPs and wider market developments, defining relative or absolute efficiency could be difficult and inaccurate. The use of RESPs as holistic, area specific network plans creates multiple different scenarios for each DNO to base their business plans and could remove some agency when defining network need and therefore some of the efficiencies that can be achieved by DNOs in this space. Strategic goals that could be identified through RESP like decarbonising an industrial cluster do not have ready comparators, unlike activities that are more repeatable such as like-for-like asset replacement. This creates difficulties in determining an efficient cost through benchmarking, let alone when overlaying efficiency frontiers and associated challenges.

While scrutiny must still be applied to ensure strategic projects are delivered for the best cost, specific levels of performance based on metrics of output per unit cost or efficiency percentages are likely to be unrepresentative as project specific factors such as geography and historic network design have a significant bearing on these project types (for instance, in HOWSUM). Driving efficiency of RESP originated projects will therefore require more bespoke approaches, rather than having an additional efficiency targets applied arbitrarily to linked allowances.

45. Do you see any reason why we should not implement the proposed changes to the calculation allowed returns, consideration of investability and assessment of financeability that we set out in RIIO-3 Sector Specific Methodology Decision – Finance Annex for ET, GT and GD?

Broadly we agree with Ofgem’s proposed changes to prioritise investability and financeability in setting the financial framework for RIIO-3. In particular, we note that the changes in the calculation of the allowed Cost of Equity (CoE) and changes to the Cost of Debt (CoD) mechanism since RIIO-2 as set out in the RIIO-3 Sector Specific Methodology Decision for Transmission and Gas Distribution. As also outlined in SSEN Transmission’s Business Plan Finance and previous responses to the Sector Specific Methodology Consultation (SSMC), we have reservations surrounding Ofgem’s application of their methodology, consideration of forward-looking risk and



definition/application of the investability concept. These views are echoed in the ENA's response submitted on behalf of GB electricity DNO members.¹⁸

Allowed returns

The Weighted Average Cost of Capital (WACC) should be set based on market evidence and calibrated to reflect an efficient level to ensure the notional company is financeable and investable. The use of robust and reliable market evidence when setting the components of the cost of capital is critical. If the allowed CoE, the return due to equity shareholders, is set too low then the notional company will struggle to be considered an investable proposition relative to its risk and other investment opportunities for investors. It is important the CoE is set based on market evidence but also reflects forward-looking risks faced by DNOs and the broader sector. If this is not reflected accurately in the CoE it will leave investors under-compensated for the risk that they are taking. Similarly, if the allowed CoD is not sufficient to cover interest costs due to debt holders, then the notional company will have financeability challenges.

The overall WACC must be set to ensure the company can raise the finance to deliver the scale of investment required over the forthcoming period. We also believe it is important that Ofgem considers long-term financeability and investability given the long-term nature of the investment and increasing capital investment in the coming decades. We have therefore summarised our view on the CoE and CoD on this basis.

Whilst we believe that regulatory stability and transparency is fundamental to investor confidence, Ofgem will need to adapt its regulatory finance policies to recognise the changing macroeconomic conditions evident in RIIO-ED3. Additionally, as outlined in the ENA response, the associated risks within the sector are increasing compared to previous price controls. For example, the scale and pace of investment programmes that will be required in RIIO-ED3 in support of the changes needed to achieve net zero will be unprecedented. The sheer number and scale of projects and programmes, and the associated delivery challenges, compressed outages, planning and consenting challenges, and reputational challenges will be at a scale never experienced before. Networks face increasing risk due to supply chain capacity constraints, inflationary pressures, workforce availability challenges, growing threats to the resilience and reliability of their networks from climate change, as well as increasing threats such as cyber security, leading to increased financing costs across RIIO-ED3. Other network specific factors will need to be considered such as types of investments, operating risks, and climate/geographical factors, such as the risks stemming from the Scottish Island or challenges in our Southern Distribution licence area.

The Cost of Equity

¹⁸ [Response to Ofgem's framework consultation: electricity distribution price control \(ED3\)](#) – ENA



There are several factors which distinguish RIIO-3 from previous price controls and underpin the importance of an evidence based and risk reflective approach when setting the allowed CoE. Ofgem's proposed working assumption on the RIIO-3 CoE range significantly underestimates the required return on equity when considering the material shift in the macroeconomic environment. There has been a material shift in macroeconomic conditions which is reflected by a marked increase in inflation, commodity price volatility, significant increases in interest rates, and geopolitical circumstances. Globally there has been a step change in the scale of investment in electricity systems - it is well documented that a large proportion of Europe and North America are investing heavily in their electricity infrastructure. It would therefore be inappropriate for Ofgem to rely upon CoE regulatory methodologies and guidance developed during periods of extremely low global and UK interest rates, inflation, and relatively stable market conditions. The CoE must reflect the current market environment such that interest rates now are at a level more in line with normal economic conditions i.e. pre-financial crisis. As a result, we have used evidence based on observable market conditions while considering data over this period of volatility.

The weight and balance of evidence shows Ofgem's RIIO-3 methodology will be incorrect if it is simply based on a roll forward of the RIIO-2 methodology. The top end of the Ofgem potential range is too low as depicted by observable cross checks, even those used by Ofgem in RIIO-2. There is more than sufficient evidence that Ofgem's range is significantly below that of this market evidence.

Separately, it is important that the risk profile for RIIO-3 is compared to previous price controls when considering the required returns for investors. For example, we note SSEN Transmission in their business plan set out a review of the equity risk based on an analysis of risk, expenditure, activity, and regulatory mechanisms to identify and quantify changes in equity risk. We believe that the level of risk in RIIO-3 is significantly heightened due to several factors and this forward-looking risk and return balance should reflect this material change, something which we intend to explore as the RIIO-3 price control framework develops alongside our business plan.

We are supportive of Ofgem's SSMD approach to apply the Capital Asset Pricing Model (CAPM) as the basis for their 'step 1' assessment in setting the CoE. The CAPM model aligns with UKRN Recommendation¹⁹ while acknowledging that it is an imperfect yet appropriate model. We believe several financial parameters within Ofgem's SSMD 'early

¹⁹ [Guidance for regulators on the methodology for setting the cost of capital](#) – UKRN



view' CoE range require uplift in order to sufficiently address investment requirements²⁰, including that Ofgem should:

- Account for the convenience premium embedded in Government bonds when estimating the Risk-Free Rate (RFR).
- Remove the Cost of Living Index (COLI)-CED adjustment in the estimation of the ex ante Total Market Return (TMR), and instead deflate the nominal data provided by Dimson, Marsh and Staunton (DMS) using the CPIH historical inflation series used by Ofgem.
- Exclude the serial correlation adjustment in the calculation of the ex ante TMR.
- Inform its TMR allowance predominantly on the basis of the ex post TMR, instead of placing 50% weight on historical ex ante approaches.
- Recognise the relationship between the TMR and gilt yields, as has been done in previous regulatory decisions, as it is likely to be required for investability.
- Include Pennon in the sample of water companies considered in the estimation of the beta.

Ofgem has invited evidence to quantify forward-looking risk in their SSMD whereby they acknowledge that the CAPM is a backward-looking measure of risk that directly translates to changes in equity returns. Forward-looking evidence is therefore a key element to ensure that the risk-return relationship is appropriately calibrated whereby Beta is a base measure of risk. If it is deemed that the future mirrors the past, then the beta could be used as the core measure of future risk. However, this is not the case for either electricity Transmission or Distribution, given the scale and pace of investment programmes that will be required in RIIO-3 in support of the changes needed to achieve net zero will be a step change in investment. Other risks such as the supply chain, changes in operational requirements and the macroeconomic environment mean a fuller assessment of risk needs to be undertaken particularly when setting the allowed return as well as the design of the regulatory framework.

Cost of Debt

Ofgem's most material shift from their RIIO-2 CoD methodology seeks to address an alleged 'leveraging effect' caused by a potential mismatch between outturn inflation used for indexing the Regulated Asset Value (RAV) and forecast inflation embedded in the CoD allowance. Out of three options, Ofgem decided to implement Option 1, which involves switching from a real allowed return to a nominal allowance for the fixed-rate

²⁰ Evidence was submitted to Ofgem from the ENA covering the cost of capital and cross checks stemming from work by Oxera and Frontier Economics. SSEN-Transmission also included evidence in their Business Plan submission which based on this evidence. We have not repeated that evidence in detail but are supportive of its basis.



debt portion of the RAV. However, this implementation will align with notional assumption of Indexed-Linked Debt (ILD) portions, which currently stands at 25%.

The notional company ILD assumption need to align with the actual company ILD portions. This will enable a smooth transition to the notional allowance for Fixed Rate Debt (FRD). This will avoid skewing the assumption towards the largest DNO and allow flexibility for DNOs to make their own financing decisions.

Ofgem's decision to implement Option 1 in line with the notional capital structure contradicts the purpose of the inflation treatment.

The actual portions of ILDs vary significantly across DNOs and are materially different to the current notional assumption. The leverage effect is not fully eliminated when the actual company ILD portion significantly differs from the notional assumption. For example, over c.90% of SSEN Distribution's RAV is currently funded by FRDs without any ILDs. When implemented with the notional capital structure, 15% of SSEN Distribution's RAV ($25\% * 60\%$) will still be indexed for inflation, even though the relevant debt portion remains fixed. Therefore, the mechanism will still result in excess RAV growth, leading to what Ofgem has defined in the SSMD²¹ as an "*unearned return*" that consumers have not paid a fair price for. The implementation contradicts with the sole objective of the remedy, as it leaves room for a leverage effect and thereby generates potential out / under performance for equity.

The CoD mechanism must be calibrated to ensure that debt costs can be fully compensated for under different scenarios in particular when there are higher interest rates which we have seen in the last few years. This will otherwise cause unnecessary downward pressure on credit metrics; financeability / investability metrics and the design of the CoD mechanism must be based on market evidence and Business Plans.

Financeability and Investability Assessment

Network operators must have sufficient operational resources available to deliver our licence obligations across the price control period and in the long-term, with a focus on maintaining a strong investment grade credit rating to reassure both debt and equity investors. Financeability has been central to price control decisions historically, and for RIIO-ED3 it has never been more important. Financeability has typically been based on credit metrics that underpin credit ratings from the respective credit rating agencies. However, in previous price controls, equity financeability was used as a core element to the financial framework through topics such as the balance of risk and return through Return on Regulatory Equity (RoRE) ranges, dividend yields, and funding requirements. The introduction of the term 'Investability' is reflective of the themes in equity

²¹ [RIIO-3 Sector Specific Methodology Decision – Finance Annex](#) – p34 - Ofgem



financeability but has not been defined by Ofgem specifically. As a result, we propose it reflects the following factors:

- Equity returns reflecting market evidence and macroeconomic factors such as higher interest rates.
- Risk-adjusted equity returns to account for forward-looking risk.
- Globally competitive returns to attract and retain investors.
- Efficient and fully financed debt costs, including transaction costs, to withstand higher interest rates particularly given the scale of debt capital required over RIIO-ED3.
- Appropriately funded costs of issuing equity of at least 5%.
- Strong investment grade credit rating (i.e. at least Baa1/BBB+).
- Cashflow measures that do not overburden funding requirements similar to previous price control measures in the short, medium and long-term.²²

We believe that this objective, if properly reflected, will ensure returns and cashflows are sufficient for both new and existing equity investors as well as supporting key investability measures.

The capitalisation rate is a material cash lever that will allow for SSEN Distribution to remain financeable. Ofgem's RIIO-3 SSMD for Electricity Transmission (ET), Gas Transmission (GT) and Gas Distribution (GD) proposal to align licensees' capitalisation rates to reflect natural split would have a subsequent impact on financeability.

In RIIO-ED2 and T2, Ofgem decided on a capitalisation rate below the natural rate to aid cashflow and financeability.²³ It is possible this policy would need to continue into ED3 depending on the scale of the capex programme and the price control in the round, but at this stage we expect that some adjustment will be required similar to previous price controls. We will evaluate the adjustment based on the data, evidence and other aspects of our Business Plan as part of the process. We encourage Ofgem to consider a similar policy in which going lower than the natural rate may be necessary. This would support cash requirements, balance charges over time, and optimise the volume of debt and equity funding as part of the notional DNO being financeable and investable.

²² It is also important this is in the best interest of consumers and not a simplistic reference to technical asset lives in isolation.

²³ In RIIO-T2, Ofgem stated they set a lower capitalisation as part of: "Avoiding over capitalisation, as this could result in less fast money than might be reasonable, which could hamper company investment and consumer interests.", [RIIO-2 Final Determinations – Finance Annex \(REVISED\)](#) – Paragraph 11.8 - Ofgem



46. Do you see any reason why we should not implement the proposed updates to financial resilience requirements that we set out in RIIO-3 Sector Specific Methodology Decision – Finance Annex for ET, GT and GD?

Ofgem proposed the below financial resilience measures in the finance annex of the Sector Specific Methodology Decision for ET, GT and GD:

- Amend the licence condition to ‘require’ licensees to maintain more than one investment grade rating rather than ‘use reasonable endeavours’ or ‘all appropriate steps’.
- Amend the dividend lock-up trigger to be the earlier of reaching BBB- with a negative watch / outlook and 80% regulatory gearing
- Amend the Availability of Resources requirement for board certification to require that the licensee states that, based on the agreed assumptions, it has sufficient financial resources to cover the entire price control period or a minimum of three years ahead.

Ofgem also announced its call for input on the energy networks ‘*Ring fence review*’ on 18 September 2024, which included a number of changes to existing ring-fencing arrangements to improve the financial resilience of the industry.

Our view on Ofgem’s proposed financial resilience measures and any amendments to the ring-fencing arrangements is consistent with SSEN Transmission’s SSMC response as well as our response to the energy networks ‘*Ring fence review*’. We firmly believe that Ofgem’s proposals are excessive because existing regulatory measures on financial resilience have been successful in guaranteeing a resilient industry. Existing financial resilience related measures include the following:

- Ultimate Controller Undertaking
- Disposals and Charges
- Cross-subsidies
- Restriction on Activity and Financial Ring Fence
- Availability of Resources
- Indebtedness
- Reporting under Regulatory Instructions and Guidance (RIGs)
- Tax clawback provisions which trigger in circumstances where a company's gearing moves away from the notional company's gearing

We believe that these measures will continue to provide effective early warnings in case of financial distress despite the ongoing expansions to fund net zero targets, and that any further measures and disclosures would be excessive.

Statutory reporting requirements and independent external audits provide further protection against company going concern assumptions. Statutory financial statements are prepared on a going concern basis and audited by external independent auditors. External auditors are required to scrutinise financial ratios, cash flow projections,



company plans, and internal controls to ensure the viability of the ongoing basis of accounts. They are liable to report on any material uncertainty relating to events that may cast significant doubt about the company's ability to continue to adopt the going concern basis of accounting. Measures relating to the 'going concern' concept go beyond information provided on the 'Availability of Resources statement', thus there are duplicate efforts already in place to ensure financial resilience.

The Viability Statement included within the financial statements provides additional early warnings of possible financial distress in the longer term. An update of the UK Corporate Governance Code in September 2014 introduced a requirement for the Board of Directors to make a statement in the Regulatory Report and Accounts as to the long-term viability of the Company. The Viability Statement typically covers a period significantly longer than the 12-months period addressed in the going concern assessment and provide insights into the board's evaluation of the potential challenges and uncertainties that may impact the company's ability effectively operate over the longer term. It quantifies principal risks / uncertainties and forecasts the headroom if all principal risks were to materialise at once and thereby indicates potential financial distress.

Increased financial resilience requirements would incur additional costs to companies which will be passed on to consumers. Such additional cost should be associated with additional benefits to consumers. Additional disclosure requirements and credit rating requirements implied in the SSMD lead to extra costs to companies and these costs will be passed on to the consumer. Ofgem should consider whether these measures provide any additional benefits to consumers, given that we believe sufficient statutory and regulatory safeguards already exist to secure the financial resilience of the industry.

47. What are the key factors (including benefits and costs to consumers) that Ofgem should take into consideration when conducting its review of the appropriate approach to regulatory depreciation in ED3 and beyond?

Ofgem's rationale for increasing asset lives from 20 years to 45 years in RIIO-1 included ensuring intergenerational fairness and aligning company revenue to its annual and economic investments. Ofgem expected that increased depreciation assumptions would bring it closer to the actual economic life and the use of the assets. However, we strongly believe that the increase in asset lives to 45 years is having perverse effect by undermining intergenerational equity while compounding financeability problems over the energy transition.

The increase of asset lives created two depreciation profiles with new assets invested from RIIO-1 to be depreciated at 45 (implemented gradually across RIIO-1) and historical assets to be depreciated at 20. Having two depreciation profiles has its own inherent issues that brings disparity to the whole regime. The historical asset base that is being



depreciated at 20 is now gradually decreasing and will be completely depreciated by 20 years into the new regime while post RIIO-1 capital additions that are being depreciated at 45 years have not been accumulated enough to provide sufficient depreciation income. This creates a period of under recovery to licensees and artificially reduces the customer bills in short to medium-term, until the new asset base catches up to increase depreciation.

NERA has conducted an extensive analysis on the existing regulatory depreciation policy. In its report NERA²⁴ states that year 2036 as the year that an average DNO would hit the lowest point of depreciation income, and it is only 45-years after the end of ED1 (late 2060) that the depreciation charge will return to the level if Ofgem had not implemented change. Therefore, under the current methodology, customers pay less in the short run but more in the long run, as slower depreciation results in higher RAV and higher return element. This clearly violates one of the fundamental aims of changing the depreciation policy – ensuring intergenerational fairness - by unfairly pushing the cost to future generations.

The reduction in depreciation income also creates material financeability issues for licensees. NERA in its report²⁵ argues that during the period of under-recovery, the reduced cashflows will create negative implications to licensees' credit ratings. A negative outlook in credit ratings can weaken the sector's attractiveness to investors. This raises alarming concerns about the financeability and investability of the sector, especially during the critical phase of the net zero transition, which requires higher capital investments.

One other objective of the increased asset lives is to align regulatory depreciation with the actual economic life of assets. However, we believe that the current depreciation policy of 45 years of asset lives is materially different to the actual economic lives of DNOs' asset portfolios. For example, in SSEN Transmission's business plan²⁶ we provided evidence that the average technical asset lives of SSEN Transmission is lower than Ofgem's regulatory depreciation policy, especially due to the higher proportion of offshore assets required for RIIO-T3 deliverables. We believe that although the technical aspect should be considered, it should not be the dominant factor to determine the correct regulatory asset lives. While we aim to conduct more detailed analysis on this as the RIIO-ED3 consultation progress we strongly emphasise that Ofgem should reassess the actual asset lives of licensees as well as those other aspects such as the intergenerational on consumers and cash flow requirements over the short, medium and long-term.

²⁴ NERA (2025), "Depreciation Policy for RIIO-ED3/T3", Prepared for ENA, January 2025.

²⁵ Ibid.

²⁶ [T3 Business Plan](#) - SSEN Transmission



During RIIO-T3 consultation Ofgem introduced a new CoD compensation methodology by introducing nominal allowance for fixed rate debt. Though this methodology was brought in to eliminate the leverage effect from inflation, it also has a positive impact on short to medium-term financeability via increased net returns. However, NERA in its report²⁷ has provided clear evidence that even introducing the nominal allowance for fixed rate debt will only partially solve the underfunding issue that occurs due to higher asset lives used for regulatory depreciation. Therefore, we strongly recommend Ofgem to consider the following factors when conducting its review of the appropriate approach to regulatory depreciation:

- Fairer intergenerational balance of charges and avoid artificially pushing costs to longer term in attempt to reduce current consumer bills
- Ensure financeability and investability requirements of the sector and consider investor expectations of payback periods
- Average actual economic lives of new assets as transition to net zero progress

The report of the analysis conducted by NERA on current regulatory depreciation is submitted alongside this document.

Part 4: Smarter Networks

48. How should the price control encourage ongoing development of the DSO role and activities to optimise whole system benefits for existing and future consumers?

49. What should the role of the DSOs be in identifying and delivering whole system benefits?

We answer Q48 and 49 together.

We agree that the DSO function will be critical in ED3 as delivery of network capacity and optimisation become even more important in the context of widespread electrification.

In line with our answers on the use of flexibility in Section 2 (Q10, Q14 and 15), we agree that unlocking full consumer value through flexibility requires a whole system approach, in recognition of the growing contribution distribution flexibility will have in managing system intermittency in the future. As the Framework Consultation recognises, there is still a role for flexibility to manage the network optimally, especially in cases for instance where confidence over the levels of future demand is relatively low – and we expect it to remain an important part of the DSO toolkit in ED3.

We think the DSO Incentive Framework and the Innovation Framework are driving good development of DSO capabilities and the effective integration of these capabilities as a whole. Given the DSO Incentive was introduced in ED2, and that we only have one year

²⁷ NERA (2025), “Depreciation Policy for RIIO-ED3/T3”, Prepared for ENA, January 2025.



of performance data, evolutions rather than wholesale reform or a complete change of direction are likely to be the most appropriate to give DNOs regulatory consistency.

We agree that the focus in ED3 should be on delivering whole system benefits for existing and future consumers. We are working closely with NESO, Ofgem and industry on the development of tRESP and RESP, which will act as a cross-vector convener to identify strategic, regional energy requirements. A whole system approach extends to the DNOs role in ensuring its networks are available and efficiently sized to unlock the benefits of flexible demand and Consumer Energy Resource (CER), access to flexible generation and also enabling their ability to access wider markets such as NESO ancillary services.

50. Our historic approach to publishing and sharing datasets has been stakeholder led and focused on establishing good digital foundations in the DNOs. With the rapid pace needed for enhanced data and digitalisation, should we instead be considering incentives around strategic priorities, such as network planning, flexibility, and connections?

At SSEN Distribution, we have consistently demonstrated leadership in data sharing and digital innovation. As the first DNO to publish aggregated smart meter data, we set a benchmark for transparency by providing daily data from two million smart meters. This delivered the granular insights requested by stakeholders to help unlock flexibility and has the potential to unlock £3.4M of societal value per year.²⁸

Collaboration is central to our data-sharing approach, exemplified by our DNO-first partnership with Icebreaker One and the implementation of their trust framework, FIRST, which informs industry best practice. The importance of data interoperability standards has been repeatedly highlighted through stakeholder engagement and an area where we continue to lead by hosting an ENA session on the development of DNO smart metering interoperability standards and DNO Collaboration Plans. These plans aim to establish a consistent, industry-wide approach, further demonstrating our commitment to fostering collaboration and innovation. The collaborative approach also offers benefits through inter-DNO digital tool sharing. Our deployment of the Integrated Network Management software, originally developed under innovation and made available to all GB DNOs, demonstrates our commitment to use best-in-class solutions and maximising return on the investments made by GB's energy customers. These achievements and initiatives highlight that the current framework has been effective at encouraging progress.

Incentivising data sharing and digitalisation at ED3

Looking ahead, we are determined to continue leading in this space, reflecting our belief in the whole-system benefits of sharing datasets. Through initiatives such as our role in Open Energy and the early adoption of the Data Sharing Infrastructure Pilot, we are

²⁸ [DSO submission 2024](#) - SSEN



fostering a collaborative approach that prioritises shared outcomes and system-wide benefits. To sustain this momentum, a clear regulatory steer from Ofgem on the standards for data quality required for sharing is essential. Recognition of the necessity of good-quality data will underpin future progress and ensure that data sharing continues to deliver value. We also think that data and digitalisation is an area Ofgem need to be very clear regarding the relative roles of collaboration or competition between DNOs given the importance and efficiency that comes with consistency and only investing once in digital backbones and trust frameworks.

We believe that the ambition and progress demonstrated in data sharing and digitalisation should be appropriately recognised. These efforts deliver significant benefits for customers, service providers, and DNOs by acting as catalysts for change, empowering customers, and enabling whole-system decision-making. While we agree that ambition in this area should be incentivised, we do not support the introduction of a bespoke incentive for data and digitalisation. Instead, we believe the most effective recognition would be through the Business Plan Incentive and DSO incentives, if retained, which align with broader strategic goals.

Raising collective standards of digital capability relies on a shared commitment to data sharing across all DNOs. A key concern is that varying levels of commitment could result in some DNOs benefiting without contributing equally, or conversely undermining shared benefit through inaction. To address this, an obligation to collaborate could be introduced, potentially through a licence condition, to ensure all parties actively contribute to advancing collective digital standards and capabilities.

We are also broadly supportive of Ofgem's continued focus on standardisation as a means of ensuring interoperability. However, it is important to strike the right balance between fostering innovation and driving standardisation to avoid the risk of limiting opportunity for funding for innovation. We believe that a framework which encourages collaboration without stifling competition is key to achieving this balance. This could take the form of DNOs competing for the best product within a common standard framework for deployment, ensuring that both collaboration and innovation are promoted, and stakeholder needs are best met.

It is also important that Ofgem recognise the cost burden associated with data and digitalisation transformation and are willing to sufficiently fund ongoing investment. This investment should reflect both the scale of the challenge as well as the scale of benefits unlocked by these fundamental capabilities. To ensure this commitment is realised, there must be greater flexibility in accommodating the inherent uncertainty in CBAs for data and digitalisation investments, particularly given the evolving potential applications and their associated benefits.

Smart Optimisation Output



The Smart Optimisation Output (SOO) licence obligation, introduced at the start of ED2, has successfully facilitated greater collaboration between DNOs and stakeholders and developed into a key leadership area of our data and digitalisation area. One of the key elements of the SOO, our Data Portal, now provides access to 24 datasets, including near real-time data, to facilitate collaboration and deliver whole-system benefits.²⁹ The strong customer demand for this data is evident, with 12,000 visitors accessing the portal, 110,000 page views and 166 data requests since launch in October 2023, validating our focus on sharing data that customers find valuable and relevant.

However, a key challenge has been the lack of common methodology in the guidance as well as a lack of common format or standard for some of the data shared. This has led to inconsistent approaches across DNOs and, ultimately, varied customer experiences. Introducing more prescriptive guidance on data formats and standards would be a valuable evolution of the SOO for ED3 by enhancing consistency and improving outcomes for stakeholders.

Ofgem should also recognise the effort required to implement wholesale changes to reporting and data-sharing processes. Likewise, Ofgem should recognise the additional friction and delay that arises when there are inconsistencies or ambiguity in data triage opinions from Government and regulation, and the significant reduction in burden that would be achieved with clear direction by Ofgem.

51. How can we enable greater development of internal digital expertise in its licencees?

We have demonstrated our intent throughout ED2 to develop organisational alignment capabilities and promote an agile culture to empower our people, attract new talent and facilitate workforce renewal.

The refresh of our digital strategy, informed by extensive internal stakeholder engagement, has identified the need to prioritise building a stronger digital culture. This will be key to maximising the value of new tools, platforms, and capabilities delivered through our transformation efforts, while reinforcing the improvements in digital architecture, data systems, and partnerships already built into ED2 delivery. Strengthening our internal digital culture will enhance in-house expertise - enabling us to deliver greater value and support to our licensees as well as driving future whole-system collaboration and partnerships.

To build internal digital expertise, we are focused on developing a stronger digital culture through training programmes to enhance digital skills, confidence and leadership behaviours, ensuring inclusivity and support throughout the process. This internal

²⁹ [Data Portal](#) - SSEN



upskilling will be delivered through our culture programme with initiatives such as data camps and other training modules.

Transitioning towards the operating model detailed in our data strategy will begin to connect teams in new, data enabled ways through data literacy and our internal data marketplace. Additionally, we are embedding digital expertise into the business by continuing to foster partnerships with universities. This will be complemented by a strategic partnership plan to leverage commercial opportunities and strengthen collaboration.

We have a clear plan and vision for the development of internal digital expertise – realising it is essential to releasing the significant efficiency improvements and enabling the system-wide benefits that enhanced digital capability offers. However, making this ambition a reality requires Ofgem’s recognition of the step change a fully digitalised system represents, and its importance through appropriate funding mechanisms. It is important that Ofgem ensures the associated cost assessments are appropriate, facilitating the necessary investment.

Digitalising DNO reporting

We fully support the ambition to use digitalisation to modernise elements of regulatory reporting where possible and are committed to developing new digital capabilities and building digital internal expertise. This offers the opportunity to provide the regulator and consumers with enhanced network performance insights, thereby improving transparency. However, we note a current lack of central guidance in this area. Such guidance is essential to set a clear direction of travel and ensure a consistent approach across network companies, raising collective digital standards in a way that maximises consumer benefits by prioritising near-term, high-impact areas. As we continue to build our internal digital capabilities and develop a stronger digital culture, it is important that digitalisation is not prematurely relied upon to underpin a shift in the price control process and is supported by sufficient funding in baseline allowances.

52. How should network companies use AI to improve network insight and decision making (both operating expenditure (opex) and capital expenditure (capex)) and how should we be encouraging this through the ED3 framework?

Artificial Intelligence (AI) has several sub-sets, from Machine Learning to Large Language Models, all of which have unique use cases and should be differentiated between when it comes to detailed questions regarding how DNOs should use the technology at ED3. The generality of the term ‘AI’ can sometimes lead to unhelpful misconceptions, and clarity is needed to fully capture its potential benefits.

We agree with Ofgem’s position that AI will have significant implications for networks in the future. AI in its many forms has the potential to deliver significant efficiency gains



across the planning, operation, and maintenance of networks while simultaneously enhancing customer experience. To fully realise these benefits, organisations must make deliberate preparations that balance the opportunities AI presents with its associated risks. Most notably, the complexity introduced by AI is expected to require significant investment in developing digital expertise and building capabilities required to enable its effective deployment. Therefore, ED3 should be used as a stepping stone towards unlocking transformative benefits from AI.

Given that AI remains a (relatively) emerging technology, we believe that leveraging existing innovation frameworks is the most effective approach to foster AI-driven advancements in ED3. These frameworks provide a structured way to promote innovation while managing the uncertainties associated with emerging technologies. In line with this, we are building an operating framework to guide the adoption of AI systems. This framework recognises the cultural shift required to integrate AI successfully, prioritising responsible deployment and ensuring the value case for AI-driven innovation is measured and balanced.

The effectiveness of innovation frameworks to encourage AI-driven innovation has already been demonstrated through the success of several projects. For example, the *Storm AI* project funded by the Network Innovation Allowance (NIA) utilises Machine Learning to increase accuracy of restoration time predictions for customers. Similarly, the *Predict4Resilience* project, in collaboration with SPEN, uses probabilistic fault prediction to enhance storm responses. Finally, the *Fastrack* project is underway which will use AI-based forecasting techniques to assess the cumulative effect of new connection requests on the upstream network.

The transformative potential of AI hinges on the availability of data and robust analysis, reflective of the data sets being considered. As such, we believe that the focus should be on building capability to further enhance our ability to make data-driven decisions on both load and non-load investment.

Finally, we recognise the point raised in the consultation regarding the potential proliferation of AI contributing to network constraints, particularly with the increased connection of data centres. Culham, Oxfordshire, in our SEPD licence area has been designated by the Prime Minister as the first AI Growth Zone with explicit intention of accelerating AI infrastructure build, including data centres.³⁰ Large connection requests from data centres are behind a significant portion of the demand growth across our license areas, as will be highlighted in our pending LRE reopener. We expect this trend to accelerate as data intensive technology like AI continues to develop, and as the Government place greater emphasis on AI as a high growth sector. We have designed our SDP and DNOA methodologies to be able to plan strategically in response to trends like

³⁰ [Prime Minister sets out blueprint to turbocharge AI - GOV.UK](https://www.gov.uk/government/news/prime-minister-sets-out-blueprint-to-turbocharge-ai)



this; through proactive engagement with developers and local planners (in future supported by the RESP), and an iterative planning approach, our end-to end load planning balances uncertainty in need with the value of accelerated delivery.

53. Our aim is for the ED3 framework to be structured to deliver high impact, transformative innovation – do you think that further changes, alongside those proposed for the other sectors in our RIIO-3 SSMD, are required to deliver this?

We welcome the proposed retention of NIA and Strategic Innovation Fund (SIF) for ED3, as this will allow us to maintain the pace and scope of our innovation activities. The changes proposed by Ofgem in the gas and transmission SSMD are also largely welcome, but we would add the following:

- **NIA oversight:** The NIA governance process is well-established and understood across the industry and is already subject to scrutiny by the ENA Innovation Managers Group to highlight areas of potential duplication, share key learning, and support collaboration. We would look to engage with Ofgem and other industry partners to further develop the details of how Ofgem can get more actively involved in the development and delivery of the NIA programme, without slowing progress or creating additional workload for either party.
- **SIF Challenges:** Longer-term visibility of SIF challenges is particularly welcome, especially when considered alongside the recent process changes in the delivery of the SIF programme. This will allow DNOs, innovators, and other stakeholders to co-create more impactful and well-developed applications, which are more likely to deliver benefits for customers. We would also welcome any opportunity to further streamline the overall SIF process, which can be resource-intensive, especially for smaller innovators and new entrants. In particular, we would like to explore the potential to streamline the application process for the Discovery and Alpha phases to maintain continuity and pace of delivery, where appropriate.

Given the critical importance of achieving net zero, inflationary pressures, and the rising costs of transformative projects, a real term increase in the SIF funding pot would help accelerate delivery and reduce systemic challenges.

Moreover, increased coordination with public sector innovation programs, such as those led by the Department for Energy Security and Net Zero (DESNZ) or Innovate UK, could help align strategic goals. This would ensure that transformational changes facilitated by the SIF are closely aligned with Government policy.

Innovation deployment: We would welcome a flexible and pragmatic mechanism to enable greater rollout of innovation into BAU. There have already been numerous successful innovations deployed across the sector, including LV monitoring, flexible



connections, and the use of LiDAR. However, many innovations require additional support to scale from individual trials to widespread adoption within BAU, particularly when benefits are realised over the longer term.

The deployment case for BAU implementation is multi-faceted and requires more than a positive financial business case. Factors such as skills, capacity to change, new risks, and the stranding of previous solutions should form part of any mechanism being considered to enable deployment of innovation.

Similarly, there are many innovations where deployment depends on decisions made by regulators and policymakers to secure the certainty needed to support investment decisions by a DNO. We recognise that innovation projects are essential for developing the evidence and learning needed to inform these regulatory and policy decisions. However, without this clarity, there is a danger of multiple innovation projects and trials being developed to address similar issues. This could lead to a situation where projects focus on creating an ever-increasing range of solutions rather than making a decision and then innovating to make the chosen solution as impactful, efficient, and effective as possible.

While maintaining funding levels aligns with consumer benefits, additional opportunities to access funding during the price control period—via uncertainty mechanisms, reopeners, or use-it-or-lose-it allowances—are crucial for addressing unforeseen innovation needs.

Finally, we welcome the consultation's focus on scaling proven innovations and recommend that Ofgem develop mechanisms for enabling timely and equitable rollout across networks. Multi-price-control benefit gathering should also be prioritised to maximise the long-term impact of funded projects.

54. Are there any factors particular to DNOs that facilitate or challenge deployment of innovation on their own and across networks?

There are several issues that present specific challenges and opportunities for DNOs. It is important that these are identified in the eligibility criteria for NIA and the SIF Challenges. These include:

- **Resilience:** Maintaining network resilience and reliability will become increasingly important as both heat and transport decarbonise, especially when dealing with ever more extreme weather events. Innovation in this area is vital to maintaining the levels of security our customers expect.
- **DSO transition:** Significant opportunities remain for innovation to support our progress in providing DSO services, with improved forecasting, enhanced



network visibility, and appropriately embedding flexibility at scale within our operations.

- **Net zero transition:** The decarbonisation of heat and transport will impact all levels of the Distribution network. Innovation will play an essential role in developing new tools and solutions to deliver the capacity required. This could include better understanding the impact of LCTs on the network, local demand forecasting, and infrastructure delivery, especially at low voltage levels where high volumes of substations and circuits will require upgrades. This could also extend to broader digital tools, supply chain development, and workforce expansion.
- **Community energy:** Developing the community energy sector will be essential to the net zero transition. DNOs are particularly important in facilitating this change at a local level. The diverse conditions and requirements across communities pose a challenge when it comes to standardising and scaling solutions, and innovation is key to addressing this.
- **Climate resilience/sustainability:** Innovation is essential to understanding and addressing the impact of climate change on our network, as well as improving the sustainability of our networks by tackling issues such as losses and SF₆ replacement.

In addition, there are some local issues specific to certain DNOs. For SSEN, in our SHEPD licence area, this includes subsea cables and providing resilience to remote and island locations. Given the almost unique nature of these challenges, it has been difficult to use existing innovation funding routes to address them. These can be particularly complex and challenging issues to manage, and innovation offers a real opportunity to identify new solutions and alternatives.

Part 5: Resilient and Sustainable Networks

55. Do you agree that we should retain the Network Asset Risk Metric (NARM)? How should it further evolve in ED3?

Yes, we agree that the NARM framework should be retained in ED3.

SSEN is actively engaged in the further expansion and development of the Common Network Asset Indices Methodology (CNAIM) through the leadership and support of the NARMs Electricity Distribution Working Group (NEDWG). This methodology provides the necessary mechanism to support the DNOs reporting of NARM outputs. We recognise the potential increased benefits that expansion of the NARMs framework to include additional asset types would present. However, an expansion would potentially require changes to the framework to accommodate other asset classes where the availability of condition data is not currently or practical to obtain.



NEDWG have been exploring the potential inclusion of an additional 28 asset classes for consideration in a modified NARM framework operating in isolation from the tried and tested existing methodology but utilising the same principles. These asset classes, if all incorporated, would increase the GB DNO non-load intervention spend under NARM moving from 74.6% to 95% of all spend. SSEN will continue to provide leadership in NEDWG ensuring the engagement with Ofgem continues to the establish the appropriateness of these proposals.

The role which the NARM framework plays in the price control process needs to ensure it allows a ‘light touch’ approach for all the interventions planned as part of a portfolio of asset work. This requires moving away from a detailed cost assessment analysis process to one more fully utilising the £/risk point mechanism embedded in NARM. This will allow DNOs the ability to flex within period on the required interventions whilst still delivering the overall target network risk reduction. Ofgem should not be trying to assess NARMs delivery via a ‘Plan & Deliver’ model at asset-by-asset level, or even project-by-project.

Fully utilising the £/risk point mechanism embedded in NARM to set baseline allowances and moving away from cost and volume traditional allowance setting would streamline the regulatory burden and improve regulatory oversight by:

- Removing the need to provide Engineering Justification Papers (EJPs) for any NARMs asset classes including any associated CBAs. This was the intended position by the introduction of the Long-Term Monetised Risk in the ED2 Business planning process. Investment strategies should be provided to set out the criteria each DNO triggers NARMs interventions for the asset classes.
- Enabling quantification of efficiency gains in network risk reduction for license areas across multiple price control periods to allow understanding of outstanding efficiencies to be gained by each licence area. This ensures maximum value for customers by enhancing performance in network risk reduction relative to the investment made. However, while £/risk point provides a consistent measure for assessing performance against commitments within individual businesses, it does not account for the differing strategies and asset portfolios between DNOs and, therefore, should not be form the basis for setting allowances.

The evidence from network risk reduction data and IIS performance demonstrates that NARMs is driving improvements in network reliability, highlighting the framework’s positive impact on asset health management.

We note the recommendation from the National Infrastructure Commission (NIC) in their ‘*Developing resilience standards in UK infrastructure*’ report that NARMs should account for climate change-driven deterioration in asset health.³¹ There has been some

³¹ [Developing resilience standards in UK infrastructure](#) – National Infrastructure Commission



discussion of whether the CNAIM could be adapted to include measuring climate change impact. One important point to note is that CNAIM relies on post hoc inspections and maintenance cycles of varying frequencies. Whilst CNAIM could be suitable to be used as an input to climate resilience metrics and indicators, this variability of inspection cycles regarding different asset types means it is less suitable to function as a KPI for monitoring current and emerging climate-based threats or assessing a network's overall climate resilience.

56. Do you agree that we should consider a more integrated approach to managing asset health, together with load-driven expenditure, given the need to future proof for resilience (climate, cyber and physical security) and future demand? What might the risks and benefits of this approach be?

Please read our answer to Q56 in conjunction with Q24 – and Q3 – Q9 on regulatory archetypes.

Ofgem highlight that they are increasingly concerned about the issue of duplication between Load and non-Load programmes – and discuss the benefits of integrating elements of Load and non-Load strategic investment projects under one ‘Plan and Deliver’ model.

We are confident that we already have an optimised approach to Load and non-Load related expenditure that can ensure duplication between the two programmes is minimised, ensures maximum efficiency of interventions on behalf of our customers – as well as ensuring a consistent approach to network resilience across projects. We think integrating elements of non-Load investment with Load investment into one ‘Plan and Deliver’ model could risk our ability to deliver investment in an efficient way by eroding fungibility and our ability to optimise investment programmes in response to changes on the ground (see also our response to Q4).

Whilst we disagree that elements of Load and Non-Load investment should be integrated under a ‘Plan and Deliver’ model, we do think changes need to be made the regulatory reporting framework to ensure that the multiple benefits of one intervention can be captured. This would mean that whilst there is still a clear primary driver to an intervention, we would be able to report on the multiple benefits that are also delivered through one investment e.g. MVA, NARM risk reduction, SF6 reduction, resilience building, losses management etc. Being able to capture multiple benefits in this way is central to our point that Ofgem need to ensure the regulatory framework can account for whole system value and the full societal value that networks provide current and future customers. Only by doing this will Ofgem ensure the energy transition is delivered at Distribution in the most efficient way over the long term, for current and future generations of customers



A prescriptive, ‘Plan and Deliver’ approach to non-Load

We do not think Ofgem should apply a ‘Plan and Deliver’ model to non-Load investment. As recognised by Ofgem in the consultation, the NARM framework is an effective regulatory framework for non-Load intervention and has driven a high standard of asset health management across networks. As a framework, it strikes the right balance of incentivising overall network risk management and allowing networks to plan the interventions in a way that they think best meets the needs of their networks and customers. As covered by our answer to Q55, DNOs are working through how NARMS could be expanded to give Ofgem even greater confidence across more asset categories that asset health is being managed effectively. In the context of good network performance and general satisfaction on all sides with how NARMS is working, a move towards a ‘Plan and Deliver’ model for non-Load seems disproportionate.

We consider that the NARM framework is highly effective in this sense and enables Ofgem to have a high degree of confidence that DNOs are managing their assets in a responsible and efficient way, to the benefit of their customers.

Integrating Load related expenditure and non-Load

We already have robust processes to ensure that our Load and non-Load investment plans are coordinated and avoid any inefficient duplications between programmes. If a project has two or more drivers (e.g. Load and Non-Load) we identify and use ‘critical dates’ to determine when the intervention should happen and therefore in which driver / business plan volume / business plan data table programme it should sit. This approach ensures an optimised approach that is ‘driver agnostic’ – which means, regardless of the primary driver, we track multiple benefits released of the intervention. If the project sits in the Load portfolio, we ensure the risk reduction is updated in our NARM model so that we don’t replace an asset that was recently upsized via our Load programme. However this risk reduction is ineligible to be counted towards our Ofgem set NARM target for the price control - an oversight of the regulatory framework which we return to below. This works vice versa – if a project sits in our non-Load programme, we take Load considerations into account too. One example is our HOWSUM reopener. Whilst the principal investment driver of the intervention is asset health of subsea cables, optioneering work confirmed that all cable sizes considered as part of the HOWSUM reopener could provide for long-term loading requirements through to 2050. Similarly, our SDPs, which map future network need according to long-term demand projections, highlight other drivers relevant to the geographic/electrical area while planning explicitly around local network capacity.

We think there is material risk of bringing Load and non-Load capex together into one ‘Plan and Deliver’ model, with RESP as the main input. Under the current framework,



DNOs retain vital financial fungibility that enables the optimisation described above – having sufficient agility to determine the most appropriate investment driver depending on an intervention’s critical dates. If all capital investment existed in one ‘Plan and Deliver’, RESP informed model, it is unclear how health-related investments would be funded to go ahead if the Load driver changed. For instance, if a customer cancelled a planned connection or the RESP strategic plan changes, SSEN must retain the ability to do compliance and health-related investments as a competent asset manager.

This agility is particularly important given the high volume of smaller capital maintenance projects that make up a DNOs work portfolio, something that differentiates us from Transmission. In comparison to TOs, DNOs have a very dynamic portfolio with projects being routinely rescheduled and re-optimised for a myriad of reasons, including flooding and access issues. DNOs need to be agile, and anything that reduces our ability to re-evaluate our work programme and re-optimize work because of reduced financial fungibility would cause significant concern.

One Primary Driver, Multiple Benefits Approach

The current ‘One investment, One driver’ approach to regulatory recording is able to account for the important fact that similar activities with different drivers do cause legitimate variances in costs e.g. fault-based replacement compared to a planned scheme could be costlier. This is important - in the nuts and bolts of the regime, we need to be able to differentiate what is the primary investment driver for a particular intervention to be able to accurately recuperate the cost of an activity.

However, the regulatory reporting regime does need to adapt to be better able to ensure all the benefits of an intervention are captured regardless of driver. The status quo has a big blind spot for all other benefits released to our customers of an intervention, save those coming under the primary driver.

For example, in a Load driven intervention, as flagged above, NARM risk point reduction is captured and recorded by our existing processes but does not count towards our NARM targets set by Ofgem for the price control period. Our internal tracking between Load and non-Load programmes minimises the risk of inefficiency and avoids the problem of double funding across drivers – but what could be a substantial reduction in network risk is overlooked or unaccounted for under the current regulatory reporting framework. This blind spot in the current framework will become a growing issue in RIIO-ED3 as interactions between investment drivers, including Load and non-Load, increase.

Moving to an approach which captures the benefits of an intervention, regardless of the primary driver would also enable DNOs to make strategic investments to optimise delivery, for example where anticipatory investment is the most efficient option but comes with a deferred measurable output. The current linear relationship between cost



and outputs doesn't incentivise this method of network investment and we need a reporting framework that takes this into account.

Our aim is to put forward a fully optimised ED3 Business Plan that aims to deliver all outputs (MVA released, NARM risk points reduced, climate resilience, SF6 and losses reduction etc) in the most efficient way possible through a blend of proposed projects, regardless of their primary driver. This would require a regulatory reporting framework that allows us to count all benefits from all projects delivered as contributing to our targets (regardless of primary driver). The framework should not in-directly penalise DNOs for coordinating drivers, if such coordination were to result in a big swing in the risk points or capacity released we could claim. This is necessary, fundamentally, to deliver maximum value to our customers by ensuring the most efficient transition to net zero at Distribution.

57. In the context of making anticipatory investment decisions, what do network companies and other stakeholders need to enable the planning and delivery of cost-effective network resilience measures against our changing climate? What risks and opportunities do you see linked to an input-based approach to these investment plans?

Please see our response to Q18 and Q22 for commentary on the definition of anticipatory investment. We use this terminology primarily in the context of load-related investment.

The importance and urgency of embedding climate change resilience into electricity networks via business-as-usual investment decisions has been made clear by the growing impact that climate change is already having on our networks and our customers. This impact goes beyond the increase in severity and frequency of 'extreme' weather events, exemplified by the 29 exceptional event claims made by DNOs in 2023 /2024 (a fourfold increase), the flooding of substations at sites previously designated as low-risk areas, and the increased corresponding level of faults these events cause for our customers. It extends to the attritional effects of a changing climate which impacts how our network operates in a business-as-usual way – for instance warmer summers resulting in higher ground temperatures and less efficient cables with lowered rating and reduced overhead line ground clearances as vegetation encroaches faster in a longer growing season.

We therefore welcome the focus on climate change in the consultation. This is an area where we have shown strong leadership, having published a robust Climate Resilience Strategy at ED2, supported by annual strategic update and progress reports which provide stakeholders with a transparent account of our progress to date against our Climate Resilience Strategy actions – and we aim to go further in ED3.³² To facilitate this,

³² [Climate resilience strategy progress](#) - SSEN



there are four areas which would enable better planning and delivery of cost-effective resilience measures:

We need an **agreed standard of climate resilience** at ED3. This needs to be worked out at an industry level and informed by a debate with customers and stakeholders. Future infrastructure resilience is a societal challenge that spans multiple sectors with climate resilience as a key tenet of this. It is imperative that a centrally agreed standard for infrastructure resilience is considered prior to entering a period of unprecedented network build. We fully support the NIC's recommendations in the National Infrastructure Assessment report for a comprehensive set of resilience standards to be developed and published by the Government.³³ Accounting for interdependencies with other infrastructure operators and relevant agencies is critical for delivering cost-effective and efficient climate resilient infrastructure. Whilst we are already active in the Climate Ready Infrastructure Scotland forum, a broader national approach is required.

A **regional understanding of emerging climate hazards** is critical to effective deployment of climate resilience measures. This requires a bottom-up approach to ensure our interventions effectively address local challenges. We have undertaken comprehensive bottom-up stakeholder engagement and are now in the process of developing regional climate change risk assessments and adaptation plans using this feedback. These regional plans will provide greater granularity in addressing the unique challenges each region faces. This will provide a robust platform for assessing regional specific needs and will assist with identifying the level of investment required to strengthen network resilience against projected climate change. This is important as a one-size fits all approach to climate resilience would lead to suboptimal outcomes for our customers. Nevertheless, whilst regional differences should be considered, we think there would be some value to ensuring a degree of standardisation to climate adaptation plans worked up between DNOs and relevant stakeholders / authorities.

Clarity in the regulatory reporting regarding where climate resilience measures are reported is also key. We would support the introduction of a specific climate resilience investment driver within the Environmental Action Plan under CV22 which would enable greater rigor in investment decision making, help with planning interventions and ensure that resilience standards are being achieved. It would also give Ofgem greater oversight of the level of resilience-building being undertaken.

Certain and adequate funding is the most important factor in planning and delivering cost-effective resilience measures. The most effective way to achieve this is by ensuring DNO baseline allowances fully account for higher asset specifications that reflect both current and future risk. This would require accepting higher unit costs – however, it would ensure maximum value is delivered to our customers over the long-term in the form of a

³³ [The second national infrastructure assessment](#) – National Infrastructure Commission



suitably resilient and reliable network. Greater baseline allowances could be used in conjunction with measures to allow retrospective climate resilience cost recovery and targeted uncertainty mechanisms. Prioritising proactive investment in resilience delivers long-term cost efficiencies and reduces the need for reactive, high-cost interventions later. This approach would enable DNOs to undertake targeted interventions, such as measures to mitigate specific risks like flooding – and anticipatory investments, such as upsizing cables or using more weather resistant materials. It is also important to recognise that climate change has in-direct impacts – and costs – to DNOs; for example, there is a cumulative effect of multiple severe storms on our frontline personnel, particularly in remote areas where the network is hard to access. Longer working hours in harsh conditions lead to fatigue, reduced morale, and mental and physical strain – and ultimately erode our workforce resilience.

We agree that traditional CBA methods will require adaption to appropriately assess investment options in the context of a changing climate, if adequate funding is to be secured. We would welcome further discussion on how Ofgem should ‘price in’ future levels of climate resilience. It will also be essential to account for the wider value of climate resilient investments to ensure that environmental factors such as carbon sequestration and biodiversity as well as societal benefits are properly incentivised. One example is our *Nature4Networks* innovation project. This project is investigating the potential for Nature-based Solutions to be used as effective alternatives to traditional engineered approaches for protecting and enhancing assets, with positive findings where they have been applied to use cases so far. These solutions not only achieve their primary objectives but also offer significant co-benefits such as noise reduction, enhanced visual amenity, improved air quality, and elevated placemaking.

Our position on input-based regulation is explained in our response to Q3, Q4, Q7 and Q8. As outlined in these sections, our view is that the real value of introducing the ‘Plan and Deliver’ model would be in the context of providing additional certainty of strategic need for load-related activities. In the context of climate resilience, it is unclear what additional inputs Ofgem may be considering, though as noted above, we would welcome clear policy decisions for example on the level of resilience to be achieved on our network.

Finally, as set out in our response to Q24 and Q56, we do not think bringing together Load and non-Load projects into one programme would work – as this would not guarantee us the agility we need to adapt programmes of work to changes on the ground. Instead, as stated above, we need a reporting framework that captures the multiple benefits of one intervention, regardless of the primary driver – for instance, network reinforcement to enhance climate resilience may also result in NARM risk point reduction. The regulatory framework needs to be able to capture this.



58. How should we monitor progress on the delivery of climate change resilience? Do you have any specific learnings which can help shape this?

The implementation of climate resilience metrics and indicators would be a significant step forward in measuring progress on the delivery of climate resilience. The ENA working group has made good progress in advancing this initiative to date and has drafted a Climate Change Resilience Working Group Metric – Heads of Terms Document which forms a collective agreement, via the ENA and with regulatory support from Ofgem, for the underlying principles for development of climate change resilience metrics and indicators. Fundamental policy design questions do however remain and Ofgem have confirmed that they will publish a climate change resilience metrics and indicators option paper in the near future which will establish definitions and agree on an implementation process. We look forward to reviewing this paper, considering the options and working with Ofgem and the ENA Climate Resilience Working Group to ensure that the metric(s) is well designed to ensure that the regulatory framework accurately values, incentivises and provides funding mechanisms for climate resilience initiatives while enabling effective tracking and measurement.

It is important to note that the complexity of climate change resilience metrics and indicators means that deployment by ED3 is an ambitious target which should not be rushed and would require full consultation.

As outlined in our response to Q55, the CNAIM is an effective tool to inform investment decisions and manage network risk – and could contribute as an input to climate resilience metrics and indicators. However, it is not an appropriate KPI for Ofgem to use in managing current and emerging climate-based threats or overall network climate resilience in ED3.

59. Do you have any comments on the suitability of current incentives to ensure that consumers continue to receive a reliable service in the face of climate hazards?

For ease, we have combined our answer to Q38 with Q59, on the approach to reliability in the context of the increasing impact of climate change on our network.

The societal shift to electrification and the growing challenge of climate change fundamentally changes the context of electricity network reliability, and this needs to be reflected in the regulatory framework – we think the time is right to rethink the current approach.

For our customers, network reliability is one of the most important aspects of our performance. Its importance will only increase as dependency on our network deepens with the continued electrification of heat and transport, and as more embedded generation connects to our networks. Societal electrification and deeper dependency will drive several factors of change at ED3. First, our customers' expectation of our



service is evolving, with network reliability and resilience likely to be even more important to them in the future. Second, the network is becoming more complex - with greater use of flexibility and more embedded generation – meaning customers may experience quality of supply issues they currently do not. Third, to meet greater demand, we will carry out more work on the network than ever before. This means more planned outages but also, inevitably, that we carry more reliability risk on parts of the network as works are carried out.

At the same time, we are now seeing the impacts of climate change across our networks become more frequent and more intense. This is not a trend that is limited to Distribution – the National Infrastructure Committee recently reported on the growing challenge climate change poses to UK infrastructure and the need for urgent attention from Government, regulators and affected sectors.³⁴

In this changing context, it is imperative that any reliability incentive framework drives the right interventions in RIIO-ED3. It must not disproportionately penalize DNOs for carrying out the necessary interventions across the network, at the pace which will be needed in ED3. This links to the point we make in answer to Q4 and in our cover letter, about the importance of a holistic regulatory approach with all regulatory components working together in a harmonious way.

Any review of the reliability framework will need to consider its different components, which include the IIS, but also worst-served customers, GSOP and the interaction with the resilience framework. These different components must work together to ensure that the regulatory framework delivers the right outcomes for consumers, at the right cost.

Reviewing the Interruptions Incentive Scheme

Since its introduction over 20 years ago, the IIS has been successful in driving significant reliability improvements across DNOs. The societal shift to electrification and the growing challenge of climate change fundamentally changes the context of electricity network reliability compared to when the IIS was introduced, and this needs to be reflected in the regulatory framework. The cost of delivering reliability improvements in 2025 is far greater than equivalent improvements in 2005, and we think the time is right for a fundamental review of the IIS.

Any review of the reliability framework will need to consider the overall framework as noted above. This could include an overhaul of the IIS, but should consider at a minimum the following:

- **Providing clarity on how improvements in reliability should be funded**, to meet baseline targets: in RIIO-ED2, Ofgem set a clear design principle which

³⁴ [Developing resilience standards in UK infrastructure](#) – National Infrastructure Commission



stated that “*the delivery of a target level of outputs [...] should be funded through baseline allowances, rather than through incentives. Target levels should be set so that the benefit to consumers of achieving target levels is broadly balanced by the cost in higher network charges.*” Ofgem must be clear for RIIO-ED3 that the same principle applies, and ensure it is applied consistently across IIS and other incentives.

- **Ensuring the IIS framework is fit for purpose for a period of high-capacity growth.** A pragmatic approach is needed, cognizant of the fact that ED3 will entail far more interventions on the network than before, meaning more reliability risk will need to be taken as part of planned outages. The IIS framework needs to ensure DNOs are not disproportionately penalised for doing the right thing whilst still effectively managing network risk and maintaining supply. This may entail testing the category of Planned Interruptions to make sure it drives the intended behaviours from DNOs at ED3. We must also ensure that any adjustment to CI targets considers the current arrangements that DNOs currently face with the impact of the Covid years in the outturn in ED2.
- **Testing if the physical characteristics of licence areas are properly accounted for when IIS targets are set.** Our SHEPD licence area covers 25% of the UK land mass but is the most sparsely populated Distribution region in the UK (we have approximately 14 customers per km², the national average is approximately 133 per km²). It includes 59 remote island communities who are supplied and interconnected through submarine cables. Serving such remote communities across such a large area creates specific challenges in terms of storm response and meeting CI and CML targets – and these will only get worse as climate change continues to exacerbate weather events. Our teams already sometimes struggle to get to remote islands to fix faults, having to rely on one ferry provider. Ofgem’s CI and CML targets and the improvement factors must reflect the various differences between DNOs and the external factors influencing performance so that the IIS framework is properly optimised to the specific challenges license areas face.
- **Reviewing the definition of exceptional event:** In 2023/24, we had 47 days in our SEPD license area with at least twice the daily average number of faults. This compares with 29 equivalent days in the last 4 years of RIIO-ED1. These 47 days did not meet the Exceptional Event threshold under the current IIS framework but would have done in previous price controls. In addition, between October 2023 and January 2024, we had six named storms which caused a range of issues across the network including flooding at sites that had not previously been identified as being at risk. Both examples highlight a



growing trend of adverse weather where our network is severely impacted, despite our investment programme to improve network reliability over time. To underline this point, a storm of the same intensity now causes fewer faults than it would in the past because of reliability improvements. Raising the threshold of what counts as an exceptional weather event over time, coupled with the impact of climate change which causes more severe weather disruption, means the reliability improvement needed to meet targets and avoid penalty is greater than ever before. We think, as currently set, the framework leads to disproportionate penalties.

- **Ensuring targets do not overly rely on historic climate data** which increasingly does not give reliable insights into the challenges our networks will face in the short-term. For example, we are seeing increasing volumes of underground faults resulting from saturated ground due to prolonged summer rainfall. The default approach in the regulatory framework is that underground faults cannot be storm related, and therefore no exemptions are provided. What we have seen is the result of prolonged abnormal conditions which, on each day may be considered ‘normal’, but have a cumulative effect on our assets and cannot be predicted (as they are often caused by ground movement once the earth becomes saturated). We are concerned that a continued reliance on historical data to set targets and inform the regulatory approach is leading to disproportionate penalties. It is also leading to a mechanism which is not adapting to the scenarios DNOs are facing today and will continue to face in the future.

This review should be conducted before the start of ED3, potentially as part of the Sector Specific Methodology Consultation (SSMC). It will be fundamental to ensuring DNOs are proportionately incentivised to provide a reliable service to customers.

It should be informed by the wider **review of the Value of Lost Load (VoLL)**. This review needs to ensure the regulatory framework reflects the importance customers place on network reliability. However, it is important that the wider context of electrification and climate change is considered when carrying out the VoLL review. Potentially tighter IIS targets combined with a higher VoLL, which could lead to a much stronger incentive rate, could mean a more severe penalty for DNOs missing targets potentially for reasons outside of their control. For instance, Ofgem should be mindful to avoid a situation where a DNO needs to balance the risk of a large penalty against carrying out accelerated and widespread works to prepare the network for net zero (given the fact that as work is carried out on the network, because power is often moved to a ‘back-up’ circuit to enable works to take place, there is an inherent reliability risk, especially where the volumes of circuit outages at any one time is increased). This consideration has parallels to the position and work being undertaken by NESO, TOs and DNOs considering overall system



benefits, constraint costs and system risk. If the reliability framework has the unintended consequence of preventing required works being undertaken, this would not be in the interests of customers. Therefore, the VoLL review needs to carefully balance a potentially higher VoLL with any approach to target setting to ensure the framework avoids creating a situation where we are disproportionately penalised for outages (planned or unplanned).

Worst Served Customers

In a similar vein, we think the Worst Served Customers framework warrants a review. As currently structured, it can create perverse outcomes where it is simply economically unviable to intervene to improve the service of some of our worst served customers. This is especially the case in our SHEPD licence area. The current regulatory framework makes some attempt to correct this through the North of Scotland Resilience (NoSR) mechanism. This mechanism is specifically designed to fund improvements to those areas that suffer poor performance, but where the cost of improvement can be extensive. A good example is a long radial network that connects only 500 customers, typical of some of the remote areas of our SHEPD network. They could all be worst served customers under the current framework, however, under the incentives as currently set, it is economically inefficient to intervene and improve their reliability. There is a strong case that the NoSR fund needs to be increased. If left unchanged, the WSC framework could lead to a significant reliability performance gap between groups of customers in the same licence area. This could become more problematic as dependency on the network deepens in ED3, and customer expectations continue to evolve. Ofgem could look at a tiered system for Worst Served Customers which could differentiate between different levels of service being provided – the current approach is quite blunt and may not drive the right investment decisions for our customers.

Guaranteed Standards of Performance

More persistent and severe weather also affects our GSOP performance with more customers off supply. With shorter times to restore people (12 hours in normal weather, assuming the weather does not become an exceptional event), it means it is harder for us to get everyone back on supply in time, therefore we have more failures.

That is particularly true in SHEPD, where the geography means that simply getting to customers in time can be a challenge. This is most extreme in Shetland, where there is only one ferry operator - if that service isn't running, we cannot get to those customers to restore their power. Since that is beyond our control, we think the islands exemption for IIS and GSOP should be re-introduced, ensuring it only applies where our physical access to the network is prevented and there is no other way to restore supplies. We note that this would bring the framework in line with comparable performance regimes in



other sectors (e.g. Rail) – and Ofgem already make some provisions along similar lines when access is prevented in other ways (e.g. flooded roads).

Short Interruptions

In RIIO-ED2, Ofgem considered introducing a new incentive on short interruptions. We note that Ofgem does not appear to be considering this for RIIO-ED3. Any new incentive would require a robust evidence base including an understanding of impact on customers, an assessment of willingness to pay and any interactions with the existing IIS targets. There will also be a need to ensure severe-weather related performance is adequately accounted for in any targets for performance.

Other points

We would welcome an approach that is able to respond to events on the ground in a more flexible way. For example, if a DNO suffers three flooding events at substations which had not previously been judged to be at risk of flooding, this could trigger access to funding for a review of similar substations to consider increased protection. This would give DNOs greater ability to respond to risks as they materialize, and ensure customers are not exposed until the next price control.

There is also a link between climate change and workforce resilience - we are already seeing the effects of fatigue on teams responding to successive storms in quick succession. In ED3, this may serve to exacerbate existing workforce resilience challenges.

Lastly, Ofgem should consider the role of nature-based solutions when it comes to actively building network resilience to climate change and delivering reliability improvements. If standard asset specifications are required to consider nature-based solutions like sustainable urban drainage systems (SUDS) and bioswales then mitigation is built in from the start. Consideration beyond individual asset level is required too. If catchment-based approaches become a resilience investment option then multiple assets can be protected downstream of an intervention, costs can be shared as a result of shared investment from multiple beneficiary sectors, customers' money goes further, and multiple benefits are delivered back to society.

60. Do stakeholders agree with retaining and strengthening the main components of the environmental framework from RIIO-ED2?

Reducing the environmental impacts of running our business and contributing to decarbonisation of the energy system is front and centre to considerations. As such, we support the retention and strengthening of the Environmental Framework. We would encourage Ofgem to broaden the scope to cover wider sustainability elements, with environment being a key part. This is in line with the Government's Clean Power 2030 Action Plan which highlights the importance of integrating clean power and the natural



environment given the twin crises of climate change and nature / biodiversity loss.³⁵ This is also in line with the fact that our stakeholders (including regulators) are increasingly demanding rapid change: accordingly, we have already stepped up the role we play, contributing to achieving the national biodiversity strategies for both Scotland and England, understanding our sustainability impacts and dependencies across our value chain, and the interdependencies between these, and building in climate resilience measures (as outlined in our response to Q56).

We welcome the proposed focus areas of losses and SF6 within the Environmental Action Plan (EAP), however there should also be a targeted focus on pollution prevention, transport, circularity and nature. With policy and approaches in these areas developing and evolving, DNOs will need the flexibility in the framework to set suitable price control commitments and targets – this may mean that targets should be outcome-based rather than output-based where this enables DNOs to do the right thing to achieve the desired environmental and social outcomes. Specific considerations for Nature-based-Solutions (NbS) are outlined in the final section for this question response.

Embedding Sustainability into the Regulatory Framework

We agree that DNOs have a responsibility to avoid, minimise, restore and compensate for any adverse impacts of local networks on the environment. Environmental issues and sustainability must not be an afterthought but woven through the entire regulatory framework if we are to credibly deliver net zero in a way which considers the potential social and environmental impacts of proposed net zero solutions. DNOs must be provided with suitable mechanisms to balance the disruption being caused with environmentally-sensitive delivery.

The climate and nature crises, caused by decades of human disruption, must be solved in a way that delivers future social and environmental value, without any unintended or unforeseen consequences. There are evolving frameworks and approaches that enable this planning and thinking, including applying a ‘capitals framework’ to assess value across multiple capitals (i.e. financial, social, natural, intellectual, manufactured etc.) and in ensuring that NbS are included as viable delivery options. The regulatory landscape must facilitate and support this.

Regional differences are very important, and environmental or sustainability targets should be informed by local stakeholders and the value that they will experience on the ground, rather than by taking a ‘one size fits all’ approach. Establishing baseline positions is critical to ensure DNOs can adapt to changing conditions, increased burden on compliance activity and potential policy change.

³⁵ [Clean Power 2030: Action Plan](#) - NESO



The current environmental reopener provides a mechanism for funding but is already showing signs of being too rigid to allow DNOs to do what is required in the current price control. For example, while the reopener permits triggering for legislative changes during the price control period, it does not account for changes that occur between the submission of the final business plan and the start of the price control. This was evident with the introduction of the Environmental Act 2021, which mandates biodiversity net gain but fell outside the reopener's scope. Additionally, regarding SF6, while UK law has not changed, EU regulations have banned new assets containing SF6. Given that our supply chain operates globally, suppliers are aligning with EU standards, resulting in higher costs for SF6-free assets. These costs are passed on to us in the UK, but Ofgem does not permit us to use the environmental reopener to recover these expenses because there has been no corresponding legislative change in the UK.

Annual Environmental Report (AER) and Environmental Action Plan (EAP)

The Annual Environmental Report (AER), published annually, strengthens DNO accountability and we believe is something our stakeholders value. Reporting through the AER will continue to increase the transparency of the DNOs' performance against targets. There is already a template set with some clarity around metrics and measures. However, work could be done to improve this and provide clarity for stakeholders. In addition, regulatory reporting should be aligned and streamlined to improve consistency and accuracy of reporting and clearer understanding of performance.

The introduction of the Environmental Action Plan in ED2 was the necessary step change required to ensure all DNOs had a targeted focus on decarbonisation – it is critical that Ofgem use ED3 to build momentum by ensuring there is funding mechanisms for ongoing work that is already providing value to our customers. This is key to ensure environmental outputs currently set return best value over the longer term.

Further clarity around some of the baseline commitments expected would ensure rates of decarbonisation and reduction in environmental impact are consistent and continuous over time across all DNOs. We would also welcome the opportunity to include bespoke activities over and above what may be set out in the Business Plan minimum requirements that meets the needs of stakeholders.

We feel that, for ED3, the EAP should be expanded into a Sustainability Action Plan, recognising the interdependencies between environmental and social impacts, dependencies and benefits.

Environmental Compliance

We welcome Ofgem's recognition of the need to balance an increase of network capacity in ED3 alongside other important priorities, like environmental compliance. It is important to consider the impact a period of high network capacity growth will have on



our existing assets; for instance, as capacity is taken up, they inevitably become less efficient, more interventions will be required and existing asset management practices will have to be adapted to ensure asset integrity is maintained. This, and the context of an increasingly difficult climate, means there is a risk of increased environmental incidents – like assets failing sooner than expected due to being under more pressure and leaking oil. To address this risk, we will have to ramp up inspection and maintenance activity required to ensure ‘Safety, Health and Environment’ obligations are met and operationally critical assets are looked after appropriately. This needs to be appropriately funded at ED3 – and will put additional pressure on workforce resources, already a challenging area given growing workforce and skills shortages (see Q62).

We would encourage Ofgem to use the BPI to reward Business Plans that put forward ambitious plans to deliver net zero in a sustainable way – and provide funding in baseline allowances that ensures delivery. The overreliance on a reputational incentive is not in line with the broader policy direction flowing from stretching net zero targets committed to by both the UK and Scottish Governments. Introducing incentives to embed the ambition of the EAP has merit and would require further consideration. We propose DNOs, stakeholders and Ofgem work together to further explore options that would constitute a suitable regulatory mechanism to ensure delivery of sustainable approaches / solutions.

We think that the application of a capitals approach could be one way to ensure that economic, social and environmental impacts and interdependencies of network activities are considered and appropriately balanced – and we are exploring its application in the context of writing our ED3 Business Plan. We welcome the recognition that CBAs need to do more to account for the value of climate resilience measures, but as per our response to Q41 and Q42, Ofgem CBA templates should do more to assess social and environmental costs and benefits, this is particularly important in future-proofing networks. A capitals approach can set the framework for establishing this and requirements for quantifying and monetising benefits can be based on best practice, include the most up-to-date evidence-based figures (e.g. carbon rates) and be standardised for all DNOs.

SBTs

We would encourage Ofgem to ensure consistency across all DNOs when it comes to continued requirement of setting targets particularly in relation to the requirement to set science-based targets (SBTs). Currently, there is a requirement for all DNOs to set SBTs accredited by the Science Based Target initiative (SBTi) but no clarity on what scenario they should be aligned to – DNOs have a mix of current targets with many excluding losses from direct scope brackets. The difference between SBT trajectories is significant and thus could result in separate pathways developing between DNOs - and will most



certainly directly impact the efforts and level of activity required from each of the DNOs, and associated funding requirements. We encourage Ofgem to set a clear policy position here to ensure the delivery of an environmentally sustainability network across all of the UK.

IIG - SF6

We agree that SF6 should be a focus area but not just for ED3 – we need to progress activity in this area now and we have been actively seeking Ofgem approval through to progress this through the UM, with no success to date. We note that Ofgem acknowledge the impact of the EU IIG regulations will have on network companies in the UK through the supply chain and the manufacturers. We look forward to the upcoming consultation from UK, Scottish and Welsh Governments due in 2025, where they are expected to impose similar restrictions on the purchase and installation of SF6 that the EU regulations dictate. With that in mind, Ofgem should consider action in the current price control to help manage the impact of potential future updated restrictions and enable DNOs to work closely with suppliers to develop the solutions that will be needed in the future. The current mechanism criteria could be preventing progress in expanding the availability of SF6-free equipment and environmentally sustainable alternatives. It is important that we take the time to consider the impact of alternatives, or types of alternatives, and the impact that will have on future operations – like having to store and transport several different types of gas and the risks associated with that.

We would continue to support the reopener to accommodate environmental legislative change, however DNOs should work closely with Ofgem to determine the trigger points and also cover periods of time that fall between Final Determinations and Price Control starting. It is essential that the framework and mechanisms for RIIO-ED3 provide flexibility to respond to an identified need, in a timely manner and in a way that protects the integrity of the price control under which we operate.

Losses

Losses make up circa 90% of our total greenhouse gas emissions, as well as being a system issue that has a significant cost impact for our customers. Accordingly, we took them seriously in our ED2 plans with the first step to being to prioritise losses accountability and transparency by following GHG protocol rules and acknowledging them as a Direct Scope 2 emission. This meant including them in our Science Based Targets for emissions reductions. During ED2, we've made good progress to date managing our losses through updating and embedding our design standards for cable and overhead line sizing and improving the energy efficiency of our substations.

We, along with our stakeholders, were disappointed in ED2 when the price control seemed to reduce the focus on losses in the EAP but also in the assessment CBA



methodology. Unsurprisingly therefore, we welcome an increased focus in this area – however, the approach needs to be pragmatic by recognising the challenges inherent in accurately locating losses with precision on the LV network, and incentivising and rewarding ambition on losses management.

The first step should be to ensure we are sufficiently funded to make investment decisions that support losses reduction. For instance, our asset policy sizes assets for longer term demand projections which helps manage losses in the short and medium term – however this can mean higher unit costs which, under Ofgem’s current CBA methodology, can appear inefficient as the standard CBA template does not value capacity meaning the full value of long-term losses management is not captured. This should be reviewed. Second, Ofgem could consider introducing a minimum level of losses monitoring, guaranteeing that DNOs pay sufficient attention to a critical issue in a period of network growth. Third, Ofgem should use the Business Plan Incentive to recognise and reward ambitious plans to manage losses. The majority of losses occur on the LV network which, typically, is where network monitoring is still growing. This can present a challenge to accurately locating losses on the LV network – however, innovative solutions can be found. SSEN Distribution has just been successful in securing discovery stage SIF funding for our Improving Losses Analysis and Detection (I-LAD) Project. This will develop techniques using novel approaches including machine learning to automate losses data collection and modelling with the intention to better understand the total losses landscape, paving the way for better targeted management. Ambitious initiatives like this could deliver significant losses dividends, delivering great value to our customers. The BPI should be used to incentivise and reward ambitious plans to build capability or track and manage losses in innovative ways.

We would welcome further engagement with Ofgem on how the above, three step approach could work in ED3 – we think the RIIO-ED3 period could be used as a stepping stone to ED4, where the full integration of losses management into the Totex model might be possible as the level of LV network monitoring continues to increase across the sector, unlocking precision targeting of losses across the system.

Nature-based Solutions (NbS)

Across our two license areas we have 80 local authorities; 75 have declared Climate Emergencies with some setting net zero targets between 2025 and 2030. Of these 75, 26 have recognised and declared joint Climate and Ecological crises. Nature and climate are not separate considerations. Climate change negatively impacts nature, which in turn has less capacity to store carbon and contributes further to climate change. Nature-based Solutions (NbS) provide credible opportunities to tackle a variety of networks challenges, alongside delivering multiple other benefits and value to the communities we operate within.



Delivering a credible net zero means we must look beyond abatement to carbon removal. NbS provide the opportunity for DNOs to address a variety of networks challenges, alongside playing their part in tackling the joint climate and ecological crises, whilst delivering multiple ecosystem service benefits when compared to traditional asset investments. The different ED3 framework constraints and incentives that determine investment decisions require consideration in enabling investment in NbS.

To enable the wider deployment of NbS, we would expect them to become part of BAU and therefore form part of totex allowances. This might mean that such investment needs to be included in Ofgem's cost benchmarking for setting efficient costs for each price control period. Two key considerations in doing so are therefore:

- How NbS are included to ensure that this is done on a like-for-like basis with other network investments. Given the nature of NbS, and the fact that such investments may involve longer-term opex investments (for example, payments to landowners to maintain a NbS), these are not at present directly comparable to the lump-sum capex investments typically included in cost benchmarking for hard infrastructure solutions. To mitigate this issue we would like Ofgem to consider how a robust treatment for NbS (either Capex or Opex) in the benchmarking could be found to ensure all projects are being compared on a like-for-like basis.
- We would also welcome further clarity on reporting of these complex investments in the yearly RRP submissions to ensure that we are able to draw out the benefits of the interventions.

The RIIO price controls include a wide variety of ODIs, which can fund service quality improvements that are above and beyond what is included in the base cost allowance. NbS could have an impact on consumer outputs, such as customer interruptions (CI) and customer minutes lost (CML) and NBS activities could contribute towards our ability to drive improvements.

Two of the current RIIO-ED2 ODIs are likely to be of relevance to NbS; the Annual Environmental Report (AER), and the Network Asset Risk Metric (NARM).

The AER requires DNOs to publish an annual report on their environmental performance. This is intended as a reputational incentive - while it may help to ensure networks are carrying out environmental best practice, the sole reliance on a reputational incentive could impact on whether the decision is made to invest in individual NbS. Where appropriate and proportionate, the use of existing tools and mechanisms such as PCDs or other could be used to ensure that DNOs are not only rewarded for ambitious plans – but also held to delivery on behalf of consumers. In some cases, the delivery of an NBS



solution will come at a lower cost than a conventional solution: we consider that the current incentive-based totex framework already encourages DNOs to bring forward these solutions under those circumstances.

The NARM is a financial incentive on DNOs to maintain their assets. The condition of network assets is assessed through the Common Network Asset Indices Methodology (CNAIM) which is also the basis of the more complex asset management systems used by DNOs to decide when and where to invest. While the CNAIM applies to electrical assets (such as transformers and poles), the availability of NbS may affect its application in two ways:

- The CNAIM accounts for the way in which certain assets can mitigate environmental consequences (for example, a concrete bund surrounding a transformer can reduce the risk associated with oil leaks). At present, the methodology would not account for any alternative NbS which fulfils the same purpose (such as a bio-swale which has been designed to safely retain oil in the event of a spill). If these NbS could be proven to be effective, changes to the CNAIM could be explored to incentivise their use.
- The presence of a NbS may affect the risk probability of an asset (for example, if a SuDS solution reduces flooding risk) and DNOs may need to account for this.

Licence Obligations (LOs) and Guaranteed Standards of Performance (GSoPs) set the minimum standards which networks are expected to achieve. In principle, some types of NbS might affect the ability of a network to meet these obligations. For example, if a NbS approach to flood mitigation were less reliable than a conventional solution, then it might lead to a network breaching its GSoPs in relation to supply restoration following severe weather.

Where the focus is on NbS that will deliver network performance to at least the same level as conventional solutions, minimum standards for network performance should not be a constraint. However, there may be more issues if minimum standards are prescriptive on *how* a given output is to be achieved. For example, if minimum standards require a certain approach to flood prevention this could rule out a NbS which has the same overall level of performance. As such, in setting commitments/targets for NbS investments, consideration should be given to the appropriateness of measuring outcomes, rather than outputs.



61. Do stakeholders agree with building on the approach taken to cyber resilience in RIIO-3 for ED3?

Building on our response to the RIIO-3 SSMC, cyber security and resilience remains a principal risk for the SSE Group. The ED3 price control must provide appropriate funding for SSEN's management of its specific risk. We are focused on delivering the framework agreed by Ofgem, in the context of our existing plans and dynamic assessment of changing cyber resilience risk, including heightened threats associated with geopolitical unrest. It is imperative that there is clear guidance from Ofgem on future requirements, to allow Distribution licensees to build these into ED3 plans, and to inform any required changes to the regulatory framework across the electricity sector.

We welcome Ofgem's proposal to implement a principles-based approach. It is important we are funded from a risk mitigation perspective, as opposed to an overly prescriptive or narrow scope – this is in line with the requirement in the NIS Regulations for an OES to “take appropriate and proportionate technical and organisational measures to manage risks posed to the security of the network and information systems on which their essential service relies”.³⁶

We agree that the current approach to regulating cyber resilience within RIIO-ED2 presents a material regulatory burden, and we are supportive of the intent to streamline the framework.

Considering specific proposals Ofgem has taken forward in RIIO-3:

- **IT and OT plans:** We agree with the decision to develop a single cyber resilience business plan that is agnostic to IT and OT.
- **Scope:** We welcome Ofgem's response to consider funding requests for systems and assets which are not subject to the NIS-R scope. We agree with other respondents to the RIIO-3 SSMC that there are systems, assets and processes which are not caught within the NIS-R scope which, if attacked, may pose a risk to cyber resilience, and we agree these should be eligible for funding under cyber resilience allowances. Our primary obligation is to implement appropriate and proportionate risk management, which is a wider and more flexible obligation than that defined under the framework against which Ofgem assess us, and we think that the regulatory framework for cyber resilience should reflect this broader requirement.
- **Allowances:** We agree with the principle of funding the majority of cyber resilience activities through baseline allowances. Ongoing uncertainty is present in these workstreams due to the inherent nature of cyber threats, in addition to

³⁶ [The Network and Information Systems Regulations, 2018](#)



market conditions (including resource and supply chain challenges), but we currently believe that baseline funding complemented by reopeners (potentially including reopeners in addition to the mid-period resilience reopener) seems a balanced approach to managing this uncertainty. We note the flexible approach to possible use of UIOLI allowances, and will consider whether this is relevant to us as we develop our business plan.

- **PCDs and reporting:** We welcome streamlining of PCDs and associated reporting. The PCD framework is a relatively heavy administrative burden, primarily due to annual reporting requirements.
- **Reopeners:** We agree with the continued need for reopeners, given the potential for changes to the cyber threat and regulatory landscape, and associated activities and costs to meet these. We support the proposal that reopeners can be used to amend baseline funding in addition to new projects. Licensees should also have the ability to trigger the reopener window. We are concerned that only one window mid-period may not be adequately flexible to manage uncertainty in this area. There must be clarity on Ofgem's future requirements well in advance of ED3 business plan submission, and / or a mechanism within the framework to allow OES to bring forward updated plans for funding. We agree with the proposal to have no materiality threshold.
- **Guidance:** We welcome the provision of guidance documents and templates, including the Cyber Resilience Business Plan Requirements document; but we note that where these must be updated or tailored to the ED3 price control, this must be carried out in good time to ensure requirements are clear and able to be implemented before the price control starts. We also note that we must have sight of Ofgem's future requirements well in advance of Ofgem's SSMC on RIIO-ED3 if we are to understand and confirm our views on how these interact with the proposed ED3 framework.

We welcome confirmation of detailed proposals in Ofgem's SSMC for RIIO-ED3.

62. What specific issues are network companies facing in relation to the skills and capacity of their workforce and what measures should we take through the regulatory framework to mitigate these issues?

We agree with Ofgem's characterisation of the workforce challenges facing DNOs in ED3. Workforce resilience is critical to enable us to deliver for our customers and meet local and national net zero ambitions, and we are already making a concerted effort to ensure we have the right people with the right skills to deliver our current programme of work in ED2. A manageable ramp up of work and workforce is the only way to ensure we have sufficient people with the right skills to deliver in ED3.



Workforce Challenges

- **Skill gaps and staff shortages:** we are already experiencing staff shortages in key areas, including operational roles (lines-people, jointers, engineers, protection, wayleaves, etc.) which directly impacts our ability to deliver existing plans. Shortages are currently exacerbated by the fact we have an aging workforce and, even after implementing deliberate policies to extend careers and ensure a good transfer of knowledge, the number of retirees hampers our efforts to build up our workforce to deliver current and future work. We are also feeling the effects of a broader trend in the UK away from STEM careers with fewer looking to start a career in electricity networks and/ or showing an interest in craft roles in particular. There is a regional aspect to skills shortages and we see geographical hotspots where turnover is higher than elsewhere – we would be happy to follow up with Ofgem directly with more detail in this area. Skill gaps and shortages could become a greater problem when those same areas where turnover is high require greatest network buildout in ED3 – or where other pressures are already placing a strain on existing workforce. For example, in remoter areas of our northern SHEPD licence area fatigue caused by responding to issues caused by successive, severe storms is a growing issue.
- **Competition from with other sectors:** as activity in the energy sector ramps up, we are seeing increased competition for the same (or very similar) pool of potential employees. We are seeing greater competition for skills across both our licence areas, with transmission, renewables, and supply chain businesses vying for the same resources.

Managing our workforce pressures

We are already proactively managing our workforce pressures through implementation of our workforce resilience strategy. This has two main pillars – ensuring we develop the people we have and ensuring we are attractive to a diverse group of prospective employees.

- **Active Resource Management** to ensure we achieve maximum productivity with the resources we have. This includes a multiskilling approach to training where there is a business need to do so – ensuring we get the most out of training resources and empowering our people to do multiple jobs or tasks when intervening on the network. Active resource management also includes contingency planning – we have established backup resource pools and alternative sourcing for critical roles, allowing for rapid deployment in cases of unexpected shortage.
- **Apprenticeships and trainee programs:** taking on apprentices and trainees is an important part of our future workforce pipeline. In 2023, SSEN Distribution



welcomed 119 learners – 34 graduates and 85 apprentices / trainee engineers. However, there is a limit to the number of apprentices and trainees our operational staff can accommodate without beginning to impact their ability to deliver – and, in some areas, we are already reaching that ceiling. We are being more proactive than ever before to attract a new generation of employees, ensuring we engage with younger year groups in schools as well as older students, to highlight SSEN as a potential employer. We have attended 12 STEM events this financial year and reached approximately 2,100 young people. In addition, we've opened our training centres to local schools in another attempt to engage young people as prospective employees.

- **Training centres and upskilling programmes:** we are one of the first DNOs to create our own upskilling programme which takes a total of 12-18 months to complete (depending on the role and prior skills) and enables existing employees to become multi-skilled, enabling them to do multiple tasks or jobs on a single project. This programme also allows us to target people from outside of our sector with transferable skills in so called 'sunset industries' – including high carbon industries like oil and gas, and traditional car mechanics looking to retrain. We look to maximise the potential of already skilled people, rather than relying solely on apprentices and graduates who can take 3-4 years to train. We expect to expand this programme to fitters to help with the increasing demand. This programme received an award nomination at the Utility Skills recognising our innovative approach to recruitment.

Options for Regulatory Intervention

There is a clear role for the regulator to help DNOs build workforce resilience – however, the role of central Government is central to ensuring our access to a skilled workforce to deliver future plans; the UK's skills strategy, immigration policy and the pending Industrial Strategy (expected Spring 2025) will all impact our ability to recruit the people we need to deliver future plans.

- **Collaboration and standardisation between companies:** we would welcome greater collaboration between companies on trainee programmes. This could be a step towards greater workforce resilience by preventing companies free loading and benefiting from others' training programmes, without themselves investing in the development of the future workforce. Greater standardisation of qualifications and easier authorisation processes between networks might mean a more collaborative approach to training is possible. It is notable that DSO Entity, the industry body for European DNOs and DSOs, has called for a European Grid Academy to be set up within the framework of the EU's Net Zero Academies. We should be similarly ambitious.



- **Funding for training facilities and outreach:** we would welcome further engagement with Ofgem regarding funding at ED3 for enhancement of existing training facilities and potentially new training centres. In addition, under the current regulatory framework, there is no funding for outreach work, despite the value outreach activity has both to the sector and wider society / local communities. We already place a great emphasis on outreach as an important element of future workforce resilience – incentivising this through the regulatory framework would ensure all DNOs are attaching sufficient importance to the need to attract greater numbers than ever before to our sector.
- **Government support:** there is a clear role for central Government to help ensure the UK has the skilled workforce it needs to achieve the net zero transition and realise the future green economy. The updated minimum salary requirements for Skilled Worker Visas have made it more difficult to recruit foreign labour to fill operational roles. However, it is encouraging that the Department for Business and Trade’s (DBT) consultation on a future Industrial Strategy references the UK’s comparative technical skill shortage in key areas including electrical. Similarly, it is encouraging that Skills England has been set up by the Department for Education (DfE) to identify where skills gaps exist and how they can be addressed. The establishment of the Office for Clean Energy Jobs announced in the Government’s Clean Power 2030 Action Plan is an encouraging step – we will look for opportunities to use this to highlight opportunities in Distribution. Future Government policy on visa requirements as well as work by DBT, DfE and the Office for Clean Energy Jobs will be vital to ensuring DNOs are able to recruit the skilled workforce we need for the ED3 period and deliver a just transition.

63. What specific issues are supply chains facing and what measures should we take through the regulatory framework to mitigate these issues?

Given the scale of projected demand increase and the corresponding level of network investment needed, it is important that Ofgem understands the scale of the supply chain challenge facing DNOs.

The CP2030 report estimates that 29-30% of GB’s 2030 Clean Power supply will come from onshore wind and solar, with an approximate 29% of the 27GW of onshore wind and 90% on solar will be connected directly to the Distribution network by 2030. Alongside the embedded generation challenge, a societal shift towards electrification of heat and transport is underway, and we could see as many as 4.2 million Battery Electric Vehicles in our licence areas by 2035 and 1.5 million domestic heat pumps.³⁷ This massive increase in UK electricity demand will translate to a huge number of portfolios, programmes and projects across a range of voltage levels, engaging a wide spread of

³⁷ SSEN Distribution Future Energy Scenarios for [SEPD](#) and [SHEPD](#).



stakeholders in thousands of different, individual communities. The heterogeneity of the projects we deliver, and the sheer number, mean the delivery and supply chain challenges DNOs face are very different to those associated with Transmission, which can be mostly characterised as one-off large project delivery. At the same time, because we operate a Transmission voltage level in our SEPD licence area, we experience some of the same supply chain constraints as TOs, particularly for EHV assets.

Supply Chain Challenges

Volume Required: in ED2, we are already ramping up our delivery and this will continue with a step change into ED3 to meet demand and ready networks for net zero. More work will necessarily increase the volume of plant we require – as we procure more and further in advance, we inevitably take on more risk. Under our current approach (outlined below) we are able to manage this risk in the shorter-term, however this will be a greater challenge as the quantities we procure increase through RIIO-ED2 and into RIIO-ED3.

Long lead times, in particular for key EHV equipment: we operate a 132kV network in our SEPD license area, we also have major capital delivery projects at the Extra High Voltage (EHV) / 132kV level which are similar to Transmission projects and share some the same challenges. Lead times are increasing and certain assets such as transformers and GIS equipment have seen significant increased lead time, in some case from 12 months to 18 – 24 months. Supply chain appetite to risk has changed considerably in recent years and we are also competing internationally with other network operators who have greater certainty to secure capacity, making it harder to become customer of choice.

Increasing prices: we are seeing prices of key plant and materials increase, beyond what is catered for under the Ofgem RPE mechanism. For example, we have seen the average price of certain transformers more than double over the last 5 years. This in part is driven by greater international competition for assets as well as the rising cost of materials globally. Another driver is that high global for specialised equipment has created a seller's market, where suppliers prioritise first-come, first-served production. This often requires financial commitments, such as down payments, to secure manufacturing slots – introducing risks if project timelines or technical requirements shift.

Manufacturing capacity needs certainty and long-term signals to increase: suppliers need a high degree of certainty to commit the level of investment required to grow their manufacturing capacity, which then takes time to materialize. Despite the accelerating global race to net zero, high energy prices, inflation and domestic and global political uncertainty has meant that manufacturers have not grown capacity in the UK over the last five years as they otherwise might have done. We know that several of our suppliers want to develop additional capacity – however, they are waiting for greater certainty to



do so. The 5-year price control DNOs operate is not conducive to long-term certainty – however, there is an opportunity with the introduction of tRESP and RESP to give more certainty regarding the strategic need and the associated level of investment required long-term, beyond 2035. Once a supplier in our supply chain makes an investment decision to increase capacity, there is a lag before capacity materialises – meaning limited relief in the short-term. Long-term and sustained certainty over multiple price controls is key to building supply chain capacity in the way Distribution needs. The supply chain would respond badly to a signal to increase capacity only for that certainty to dissipate. At the LV level specifically, where there are relatively few incumbents in the supply chain, whilst we would expect long-term certainty to help increase the number of new entrants serving LV markets, inconsistent signals could prevent this or even drive incumbents out.

SF6 assets: in our ED2 Business Plan, SSEN Distribution made a commitment to reduce SF6 emissions from our assets by a minimum of 35% by the end of RIIO-ED2. This proactive approach is the right thing to do given the potency of SF6 as a greenhouse gas. However, the supply chain for SF6 replacements is extremely challenging. We are competing with European counterparts who have legal clarity via European legislation on the need to replace SF6 assets by 2030 whereas there remains a lack of clarity on the UK position, which serves to stifle the domestic supply chain. Currently, costs of SF6 free assets can be up to 40% more expensive and lead times can be up to 12 months. Our supply chain for SF6 free assets consists of three suppliers with only two choosing to supply 132kV assets – and here, we think Transmission Organisations will now have a comparative advantage regarding long-term certainty with the new Advanced Procurement Mechanism for TOs.

Subsea cables: we face specific challenges that other DNOs do not, in relation to our fleet of subsea cables. These have been well documented in our recent Hebrides and Orkney Whole System UM submission, and include weather impacts on installation, vessel availability and an oversubscribed market, commodity prices, manufacturing timelines and type-testing required.³⁸ As shown on page 60 of our report, the subsea cable market is oversubscribed with installation in Europe expected to grow significantly throughout the remainder of ED2 and into ED3. We expect to see increasing demand for specialised vessels, skilled personnel, and key materials, potentially leading to longer lead times, higher costs, and intensified competition for resources.

We regularly engage with our key supply chain partners who also encounter these same challenges. Our partners have identified greater visibility and commitment to future DNO workload, and continued collaboration with the extended supply chain, as essential elements of an effective commercial approach to mitigating the above

³⁸ [Hebrides and Orkney Whole System Uncertainty Mechanism Report](#) - SSEN



challenges – here, as mentioned above, introduction of the tRESP and RESP are a clear opportunity to provide long-term certainty about the levels of future investment.

Managing Our Supply Chain

Given the global shift in supply and demand dynamics, combined with SSEN’s evolving network requirements – particularly the unprecedented demand for 132kV GIS equipment – we have fundamentally transformed our procurement approach over the last decade. [REDACTED]

[REDACTED]

[REDACTED] This maintains delivery confidence while minimising unnecessary costs.

[REDACTED]

[REDACTED]

[REDACTED] we think that the threshold has been reached where Ofgem should consider proactive intervention to help DNOs with what is a critical deliverability risk at ED3. The need for proactive intervention has been recognised by Government with the creation of the ‘supply chains taskforce’ which will assess where critical supply chains, such as electricity networks, are vulnerable.

Options for Regulatory Intervention

- **Providing greater certainty through credible baseline allowances and limited / targeted use of UMs:** any regulatory model that increases certainty for DNOs - by setting credible baseline funding and through the use of automatic and streamlined uncertainty mechanisms where there is genuine uncertainty at play - will help us engage our supply chain earlier and with more confidence. This would smooth the current problem of price control cliff edges where, as networks



approach the end of the five-year period and associated funding, long-term planning entails greater risk. Greater certainty and earlier engagement could help alleviate growing lead in times for key assets as we would be able to give suppliers more accurate minimum volumes with greater confidence over a longer period. Over time, we would expect this approach to help develop vital additional capacity in the supply chain, helping alleviate some of the delivery challenges associated with long lead times. However, even with more long-term certainty about future work, it does not necessarily follow that lower unit rates or efficiencies can be achieved through the supply chain. Ultimately, our suppliers would remain (especially in the immediate to short-term), stretched and Ofgem should be careful of preventing new entrants/suppliers to the market, or driving incumbents out, by setting artificially low unit rates.

- **Real Price Effects (RPEs).** Ofgem should also revisit the RPE mechanism to ensure there is a more realistic adjustment factor if indexation continues and allowances are more reflective of market price changes experienced over and above that of inflation. This would need to ensure that DNOs do not experience pronounced fluctuations in allowances driven by the true up of forecast RPEs during the price control which could lead to material uncertainty when placing contracts. As noted in response to Q9, we think Ofgem could explore how an ex-post RPE true-up process could be used to strengthen confidence in the RPE mechanism.
- **An Advanced Procurement Mechanism for Distribution:** this would be a clear signal to the supply chain that they can increase manufacturing capacity for Distribution with confidence, but requires further consideration. It would need to be designed to meet the bespoke needs of DNOs with their low value, high volume programmes of work, and could be extended to areas where we face a particular skills shortage. DNOs should work with their suppliers to consider how this could best work – this would be an opportunity to consider how greater standardisation, both in terms of asset specification and also procurement processes might benefit DNOs and their suppliers.
- Finally, Ofgem should consider, given that Distribution and Transmission share a supply chain directly and indirectly, possible unintended consequences for DNOs of an Advanced Procurement Mechanism for TOs. Without steps taken to mitigate these, we consider the introduction of a TO APM to be a material risk to our ability to deliver in the RIIO-ED2 and RIIO-ED3 price controls which could exacerbate the above challenges – including by increasing the costs and difficulty in sourcing critical equipment in the RIIO-ED2 and RIIO-ED3 period.



64. Given our comments in Chapter 6 around taking a more proactive approach, are there any specific features of a more anticipatory or strategic investment approach that might create risks or opportunities for supply chain and workforce constraints?

The greatest opportunity presented by a regulatory approach which facilitates greater anticipatory or strategic investment would be greater certainty over the volume of work DNOs are funded to deliver, combined with greater up-front funding. However, the extent to which this eases delivery challenges largely depends on how far in advance certainty extends – the further ahead, the greater impact.

Regarding supply chain, greater certainty over long-term funding would enable us to double down on our existing approach to supply chain management, engaging suppliers earlier and enabling us to take on more risk. Network operators in the UK, Europe and beyond are competing against each other to be customer of choice to a small number of key suppliers – greater clarity over future funding and the associated work would help UK DNOs compete internationally. To help mitigate these risks, we support the work that the Government is doing to explore international trade frameworks and solutions to support the UK in securing the supply chain needed for the energy transition.

Regarding workforce, greater certainty would help us more accurately plan and anticipate workforce requirements of the future. However, wider factors (e.g. UK and Scottish Government skills policy etc.) outlined in response to Q62 are also at play and set the ultimate parameters of our future workforce resilience. Explicit funding for new workstreams designed to build workforce resilience would be a positive step. This could include larger capital investments to open new training facilities to the benefit of our customers, our contractors and the wider energy sector.

65. What would the benefits be of a geographical approach to delivering new and upgraded assets in terms of supply chain and workforce constraints?

We already take a geographical approach to delivering new and upgraded assets. The geographies and communities we serve reflect a diverse range of operating environments, supply markets and workforce pressures – and we tailor our approach to reflect this.

We use Grid Supply Points (GSPs) as common denominators to create geographically concentrated work banks across our network, capitalising on synergies and the structure of existing infrastructure to maximise economies of scale within the supply chain. This integrated approach to delivery planning also allows us to maximise outage utilisation – the ‘touch the network once’ approach.

Our procurement approach aims to deliver cost effective delivery for our customers and stakeholders taking into account the geographical, local and international supply market conditions and constraints we face. We welcome the Government’s ambition to bolster



domestic supply chains set out in the Clean Power Act 2030 Action Plan alongside effective collaboration with international supply partners.

From a workforce resilience perspective, we support the Government's ambition for a regional skill intervention approach, as laid out in the Clean Power 2030 Action Plan, where regional skill gaps and challenges are identified and tackled through targeted interventions.