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14 March 2019

Dear Dermot

Re: RIIO-2 Sector Specific Methodology consultation

Electricity North West (ENWL) appreciates the opportunity to respond to this important consultation on the application of the RIIO-2 Framework to those sectors whose price controls are due to commence in 2021. Our interest stems from our understanding that the same broad design principles that inform the methodology for these sectors could apply to ED2 and that the starting point for considerations of ED2 could be the decisions made for these sectors.

Our detailed response to the Cross-Sector Methodology consultation and the accompanying sector-specific materials is provided in 5 appendices to this letter. This response should also be read in light of previous correspondence in relation to RIIO-2.

We acknowledge the engagement we have had with Ofgem to date and look forward to the continuation of this. We support many of the proposals in the Cross-Sector Methodology as described in Appendix 1 to this letter. However, we remain extremely concerned that there are a number of areas in the Finance Annex, as described in Appendix 2, where Ofgem's proposals are inappropriate or suffer from a lack of detail. I believe these problems stem from a few fundamental issues that I address in summary form below.

1. The protection of the customer interest must not be too narrowly focussed on price reductions for current customers only. It appears that current concerns around energy costs may result in an over-correction of perceived errors at the expense of required investment in RIIO-2 and subsequent controls. The consideration of future customers interests appears to be largely absent from the consultation document. Furthermore, the protection of the customer interest through the continuing provision of patient, private capital to the energy networks appears to be risked by a series of overlapping measures without consideration of the overall effect.

The Acts of Parliament that privatised the energy sectors and created GEMA's duties were specifically developed to recognise that customer's long term interests are best served by the ongoing attraction of patient, low priced debt and equity. Multiple measures such as reductions to the cost of equity, sector average funding for the cost of debt, return adjustment mechanisms, high hurdle rates for change, limited incentives and cash-flow floors all increase the perception of risk and jeopardise the continuing provision of this essential customer benefit.

My concerns about this issue are heightened by the potential for the transition to the low carbon economy to require increasing investment in ED2 and beyond to coincide with an increased perception of risk for investors in the electricity distribution sector.

Whilst I appreciate the pressure GEMA is under in conducting this review; a course of action that acts to rethink the basis for financing this industry cannot be continued without widening this debate to the whole of Government. Global investment into this sector has been a huge success for thirty years (no matter if the Secretary of State was Labour, Conservative or Liberal Democrat), and policy departures that change this will need as wide an audience and as strong an evidence-based case for change as possible.

2. It would be disappointing if Ofgem's new approach was undermined by an inadequate process. Given the breadth and depth of consultation currently being undertaken, we are unclear how Ofgem expects to be able to meaningfully consider all contributions prior to reaching its decision on the Sector Specific Methodology in time for a May 2019 publication. Similarly we are concerned that the Impact Assessment developed to date does not follow Ofgem's own Impact Assessment Guidance and would not be sufficient quality to be acceptable to Ofgem as justification for investment by a licensee.

3. All relevant stakeholders must retain an unhampered right to appeal in accordance with Section 11c of the Electricity Act 1989 and Section 24b to the Gas Act 1986. The text in paragraph 2.20 setting out what Ofgem may do in the event of a successful appeal is unclear and can be read to imply that Ofgem is considering options that may, inadvertently or otherwise, be ultra-vires or dilute the statutory rights of licence-holders. Further clarity is required on the intent of this paragraph as a matter of urgency.

4. Ofgem's approach to Financeability needs to be in accordance with its statutory duty with regard to both individual licence holders being able to finance their activities and that licensees can secure both debt and equity finance. Whilst we note that this duty is stated in both para 10.60 and then para 4.1 of the Finance Annex, the proposals to put the onus on companies to ensure financeability and to introduce a Cashflow floor do not adequately discharge this statutory duty in the event that Ofgem's Finance proposals fail to give due consideration to the actual impacts for a specific licensee. Adopting a simplistic, all sector approach could easily result in efficient companies which suffer from higher financing costs by accident of timing becoming unfinanceable, thereby increasing the perceived risk by investors of the sector, to the detriment of customers.

We also remain concerned that Ofgem's proposals for a Cashflow floor seek to protect the interests of debt holders to the detriment of equity holders. We do not believe this is appropriate as equity as well as debt investment is needed in any efficiently financed company as Ofgem has made clear.

5. Customer and Stakeholder contributions to the Business Planning process should be valued by Ofgem and network companies. The document indicates to us that Ofgem will set a very high bar on the acceptability of bespoke mechanisms and applications proposed by network companies. Furthermore, ongoing engagement on the development of a single, GB-wide scenario for the future decarbonisation indicates this requirement for conformity may be extended to forecasts for the rate of change across the sector. Given the importance the RIIO-2 Framework is rightly placing on enhanced engagement with customers and stakeholders, it is vital that licensees are able to gain regulatory support for bespoke approaches that respond to the needs of the customers they serve or reflect specific circumstances in their regions. Ofgem must avoid seeking a 'common denominator' as this has the potential to undermine the balance established between a licensee and its customers.

Ofgem needs to be clear that customers and stakeholders are not the same and that customers may set different priorities in different regions.

As Ofgem's duty is to protect the interests of consumers, it needs to ensure that its decision making is not unduly influenced by the views of stakeholders. Stakeholder views are important to ENWL but we have been rightly challenged by the Chair of our Customer Engagement Group that these should be validated by customer views. Appropriately valuing and balancing the contributions from customers and stakeholders will increase the legitimacy of network companies' plans in the eyes of consumers as they will be able to clearly see how our service meets their needs and understand any associated bill impact.

6. Customers and network companies should not be 'held hostage' by the decisions of other sector participants. Proposals for cross-sector averages (such as proposed for Gas Distribution Return Adjustment Mechanisms) and 'pots' (such as for the Business Plan Incentives) place customers at risk of price changes that are unrelated to the performance of the network they utilise and licensees at the risk of poor decisions by other licensees. Customers should not be exposed to volatility in prices driven by the performance of companies that they do not engage with. Prices should not increase if other companies make mistakes in their business planning. Similarly, ENWL cannot control the Business Plans submitted by other DNOs and so should not be exposed to a risk that its revenues are adjusted if others perform too well or too poorly. We can have no idea how ambitious (or not) other companies plans may be, yet the current proposals tie our potential incentives and ultimately our returns to the levels of ambition in those plans and how effectively other management teams deliver against them.

Given the six significant issues that I observe within the RIIO-2 consultation to date, principally revealed within the Financing Annex, I would welcome confirmation in the May decision document that the approach to ED2 will be a stand-alone process that is:

- Based on specific consideration of how RIIO-ED1 has performed for consumers and consumer needs and willingness to pay;
- not fettered by precedent determined for the electricity transmission or gas distribution and transmission; and,
- allows plenty of consultation time in which to develop a specific methodology.

I remain convinced that these issues can be overcome and hope that with further engagement I can help you to achieve an appropriate resolution.

If you have questions on any element of the response, please do not hesitate to contact me or Paul Bircham (paul.bircham@enwl.co.uk).

Yours sincerely

Peter Emery
Chief Executive Officer

cc RIIO2@ofgem.gov.uk
cc Professor Cave

Encs:
Appendix 1 - Response to Cross-sector questions
Appendix 2 - Response to Finance questions
Appendix 3 - Response to Electricity System Operator questions
Appendix 4 - Response to Gas Distribution annex
Appendix 5 - Response to Electricity Transmission

Appendix 1: Response to Cross-sector questions

March 2019

1 Overview

Electricity North West Limited (ENWL) is an electricity Distribution Network Operator (DNO). We recognise that Ofgem is "*not consulting on proposals for the next electricity distribution price control at this stage*" (paragraph 2.30). However, we are mindful that Ofgem has also indicated that measures with the current consultation "*may be capable, in principle, of application for ED2*" (paragraph 2.31). As Ofgem has not stated which measures may be applicable to a DNO, we have sought to focus our response on those areas where we foresee Ofgem might consider there may be potential applicability or where we, as stakeholders to other network licensees, are able to contribute to the development of the controls. Absence of comment in relation to a given area does not imply ENWL is in agreement with any given position or that we deem it suitable for applicability to electricity distribution.

Increasingly the controls for each sector need to be set mindful of the growing level of interactivity of solutions to meet consumers' needs between sectors as whole system thinking develops. This response to the cross sector appendix should be read in conjunction with our RIIO-2 sector specific cover letter.

2 Introduction

CSQ1. Do you have any view on our proposed approach for considering the extent to which a successful appeal has consequences, if any, on other components of the price control?

As set out in our covering letter, we consider the wording in paragraph 2.20 to be inherently unclear. It appears that what Ofgem is suggesting is that it will develop a discretionary mechanism enabling further changes to be made to a licensees' price control decision after having reached its final determination in circumstances where a licensee successfully appeals one or more aspects of that decision to the CMA. So, for example, if the CMA were to find that Ofgem had erroneously disallowed £10m and made a consequential £10m increase to the licensee's allowed revenues to correct the error, the mechanism might be deployed to enable Ofgem to deduct £10 million elsewhere so as to 'maintain a coherent regulatory settlement'. If this is what is envisaged, it is entirely wrong for the following reasons:

- The appeals regime is not there to safeguard a 'settlement in the round'. Its purpose is to allow licensees to seek redress where Ofgem has made errors so as to allow for necessary corrections to be made. This is consistent with the EU Third Energy Package requirements that Member States "*ensure that suitable mechanisms exist at a national level under which a party affected by a decision of a regulatory authority has a suitable right of appeal to a body independent of the parties involved and of government.*"

- The CMA's powers in determining price control appeals are broad and include quashing the decision, remitting the decision back to the authority for reconsideration and determination in accordance with any directions and substituting its own decision for that of the authority and making any such directions as are necessary. It is therefore for the CMA to determine whether consequential amendments are required to the price control decision when correcting the error(s) and not for Ofgem, which must act in accordance with the CMA's determination including any directions.

- The fact that there may be a need to have regard to making adjustments to other aspects of the price control decision when correcting certain errors was expressly acknowledged by the CMA in the RIIO-ED1 appeal by Northern Powergrid. In its Final Determination, the CMA stated that it may, in some circumstances, be necessary to take care that overturning one aspect of a complex regulatory decision does not have knock-on consequences for other, unappealed aspects of the Decision (para 3.49). This is not about re-balancing a settlement but ensuring that appropriate corrections are made.

It would be very concerning if Ofgem considered it could deploy 'discretionary measures' to alter licensees' price control decisions post any successful CMA appeal in the manner which appears to be envisaged. We therefore cannot see any merit in Ofgem further pursuing this proposal. Alternatively, should Ofgem continue to pursue this proposal, it must provide further details to allow for meaningful engagement on the issue, including explaining the legal basis that Ofgem is relying on.

3 Giving consumer a stronger voice

We support giving our customers a stronger voice in developing business plans and holding us to account for delivering against these. To this end, we have proactively set up our Customer Engagement Group to critically advise us so that we ensure our customers appropriately influence our plans. This should result in Ofgem and our customers having full confidence in our proposals and promote and enhance the legitimacy of the RIIO price control framework.

4 Reflecting what consumers want and value from networks

CSQ2. Do you agree with our proposed three new output categories?

No. It is not clear to us what extent North West energy consumers have been involved in considering the three new output categories. We do not think the output categories capture the full range of outputs consumers require.

CSQ3. Are there any other outcomes currently not captured within the three output categories which we should consider including?

We do not agree with the proposed output categories and wrote to Ofgem in November 2018 in response to the draft Business Plan Guidance setting out some thoughts in relation to these. We do see merit in consolidating the current output categories in terms of outcomes but think it will be challenging to map the activities, allowances and incentives we deliver against the categories as proposed by Ofgem. We propose our output categories for RIIO-ED2 should be informed by the detailed customer engagement we are undertaking to inform our plan.

As set out in our November 2018 letter, we believe that the following outcome categories would more accurately reflect the role of network companies in RIIO-2 and what our customers and stakeholders are looking for us to deliver during ED2:

1. Maintain a safe, reliable and efficient network, continuing to act in the public interest
2. Respond to our customers, including those consumers who find themselves experiencing a time of vulnerability
3. Adapt our network to meet the changing needs of our customers, recognising the importance of flexibility, capacity provision and access
4. Transition our network and our team, meeting the challenges facing our customers today and tomorrow
5. Ensure our financial foundations are sound, delivering at an efficient cost to our customers and maintaining our attractiveness to investors and lenders.

In particular, the role of network companies to act in and on behalf of the public interest is missing from the outcomes proposed in the consultation document.

The customer outcomes should include finances, both in terms of the cost to serve our customers and what that means in terms of regulatory finance. As a network operator, we are required to make trade-offs between all of these outcomes, including costs and financing, and we believe that according all of these the same status will increase the transparency regarding decision making, by Ofgem and the licensees, and increase understanding of the decisions made by licensees.

Should Ofgem continue with the three output categories it currently proposes then this should be reviewed ahead of applying Ofgem’s proposed outputs to electricity distribution’s RIIO-2 price control.

CSQ4. Do you agree with our proposed overarching framework for licence obligations, price control deliverables and output delivery incentives?

At a simplistic level, we do believe the distinction between licence obligations, price control deliverables (PCDs) and output delivery incentives (ODIs) is useful. We recognise that some areas may require a combination or obligations, PCDs and/or ODIs as noted in paragraph 4.25.

With electricity distribution not being considered at this time, we are unable to comment in detail as to the application of these categories to ED2. The division of mechanisms between the categories and the subsequent regulatory treatment is important to ensuring the intended behaviours materialise and a broad understanding of how Ofgem intends the framework to be applied is desirable before customers, stakeholders and companies develop their business plans.

CSQ5. Do you agree with our proposals to introduce dynamic and relative incentives, where appropriate? Are there any additional considerations not captured in our proposed framework which you think we should take into account?

Incentive mechanism benefits to companies should be based upon the consumer benefit derived from the incentivised outcome. If there is a dynamic approach to target setting where discovered improvements are more rapidly consolidated into tougher targets then the quantum or benefit available under an incentive over a 5 year price control will be lower. All else being equal, this is likely to reduce the amount of investment that can be funded by a given incentive mechanism as the payback period is shortened, leading to lower consumer benefit in the relevant price control period.

If having shortened the price control to 5 years and reaffirmed its intent to take the most recent benchmarks into account when setting targets at the start, Ofgem is more concerned by sustained performance under incentive mechanisms then there may be some potential merit in introducing dynamic approaches to incentives. In such an instance, dynamic incentives can only effectively work where the parameters that allow these incentives to be dynamic can be transparently set in advance and allow licensees to assess business cases for investment. As such, we see potential benefits in the use of dynamic-absolute incentives where changes within the incentive are based on a company’s own performance and where the incentive is mechanistic in nature, allowing for a reliable estimation with regard to potential reward or penalty.

Whilst we can see potential benefits in using frontier performance to establish stretching targets at the start of price controls, we do not support the use of relative incentives within period. As previously stated, relative targets between licensees significantly increase the uncertainty associated with such incentives making it much more difficult to develop a business case to justify the necessary investment as one cannot predict the behaviour of others. Consequently, as a result of increased risk through an artificial state of competition being created overall customers may actually see an erosion in their benefit. In any event relative incentives may be very complex to effectively calibrate as companies may start at justified but potentially very different absolute incentivised positions due to for example their operating area characteristics. Similarly, they may face different levels of challenge making improvements going forward due to exogenous factors that would need to be corrected for.

Whilst Ofgem may consider price controls on a sectoral basis as this is less time consuming than reviewing licensees one at a time, licences are modified on an individual basis and we believe licences, once modified, should be able to ‘stand alone’ and not depend on variables from other parties.

CSQ6. Do you agree with our proposals to allow network operators to propose bespoke outputs, in collaboration with their User Groups/ Customer Challenge Groups?

We strongly agree that network operators should be able to develop and propose bespoke outputs to respond to the stated needs of their customers and stakeholders and that these should be subject to scrutiny from the Customer Engagement Group and RIIO-2 Challenge Panel. Even within outputs that are proposed for electricity distribution as a whole, we believe it is appropriate that the mechanisms should reflect the specific priorities of the customers whose needs they are responding to.

As previously set out, in order to ensure the legitimacy of the RIIO-2 controls and the role of customers and stakeholders in shaping these, it is essential that due regard is given by Ofgem to the regional sensitivities and the contributions of customers and stakeholders to licensees' plans. This is particularly important as Ofgem has rightly challenged companies to get customers and stakeholders more involved in shaping RIIO-2 so there is a need to allow this input to flow through ultimately to Ofgem's decision making.

CSQ7. When assessing proposals for bespoke financial ODIs, are there any additional considerations not captured which we should be taking into account?

The needs and requirements of customers and stakeholders should be the primary consideration when assessing proposals for bespoke financial ODIs. Whilst we understand Ofgem's comments in paragraph 4.43, we believe it is essential that neither Ofgem nor network companies attempt to limit the development of these where they can support the requirements of customers and stakeholders and result in additional consumer benefit.

5 Enabling whole system solutions

CSQ8. Do you feel we have defined the problem correctly?

We do not see this as a problem as such rather an opportunity to be developed to deliver improved outcomes for customers as the energy system decarbonises and believe Ofgem have not articulated a significant problem within the consultation. The word problem implies something is not working adequately and needs to be changed, whereas the RIIO framework has a proven track record of delivering benefits for customers. The industry has been looking wider than sector specific for some time now, and for Ofgem to formally consider enablers and incentives to bring whole system solutions into the price control framework is the logical next step. We see the remainder of RIIO-1 as a preparation stage to allow companies to learn how we can develop systems, processes and engagement approaches in order to harness the benefits of collaboration, wider thinking and use of technology enablers as they become available. It is key that the RIIO-2 framework enables whole system to be taken forward with appropriate incentives, an investable regime and funding of new activities to make this happen for consumers.

Whilst we recognise that there is already good quality and effective coordination between electricity network parties which is increasing in prominence and maturity with the creation and ongoing work within the Open Networks project, we do agree with Ofgem on the four areas identified within section 5.10 as potential blockers to achieve greater levels of co-ordination.

There are three other areas that need to be considered as potential blockers, some of which may be more easily overcome than others.

The first being potential limitations that may exist due to electricity and gas being covered by different Acts of Parliament and whilst this is not an area we have explored to date, we would suggest that is an area to be further reviewed to ensure that this does not cause unintentional barriers.

The second is around the difference in time periods of network companies price control start dates, with electricity transmission, gas transmission, gas distribution and electricity system operator having an effective commencement date of April 2021, whilst electricity distribution is two years later commencing April 2023. When seeking to apply price control framework solutions to some of these issues, it is important that consideration is given to the fact that electricity distribution will be working to a different framework for 2 years of the 5 year RIIO-2 period, and therefore there will need to be transitional arrangements put into place to ensure that this sector is not left behind, and is adequately incentivised to contribute to whole system thinking in the way that other network companies will be. Uncertainty mechanisms will need to be flexible to accommodate this difference in timing and is covered more in our answer to questions CSQ11 though 18.

The third is the need for DSO defined responsibilities to be developed ahead of the T2 and ESO price control to ensure that network companies are clear on their responsibilities and accountabilities at the boundary of the distribution and transmission networks.

Finally, other than the necessary technology, data interfaces and other enablers, we see one key enabler missing in the plans at present, which is the existence of a whole system CBA. Without this, there is no ability to quantifiably conclude that the solution is the most efficient for the whole system. As part of taking a whole system view, consideration should be given to the carbon impact of decisions. With increasing levels of low carbon generation, reducing losses and promoting energy efficiency of customers' equipment has the potential to reduce the marginal generation plant requirements which is increasingly more carbon intensive than alternatives. To this end, we believe that network companies should be required to consider an end-to-end carbon reduction strategy as part of investment decision making.

We envisage this will result in changes to the CBA model currently used by DNOs (and we presume other network companies) to take account of potential whole system costs and benefits of the proposed options. Examples of areas that we believe should be included are

- impact on system losses;
- enhanced VoLL;
- holistic transmission benefits;
- beyond meter benefits, such as those seen in Smart Street; and
- public safety.

Care should also be taken when benchmarking companies' proposals, cheap for one company, may not equate to cheap for the whole system and different whole system solutions should be compared through the same assessment lens of a suite of costs and benefits.

Where a network operator can demonstrate a positive benefits case then we propose that funding is made available through appropriate allowances and/or uncertainty mechanisms to allow timely deployment of solutions.

CSQ9. What views do you have on our proposed approach to adopt a narrow focus for whole systems in the RIIO-2 price control, as set out above?

As we stated in our response to the July 2018 framework consultation, we believe that the electricity distribution to electricity transmission interface (including the system operator) should be the focus for the RIIO-2 period ie a Whole Electricity System. This is in line with the proposed RIIO-ED1 and T1 definition which was recently consulted on and we feel is appropriate for the period up to 2026.

Similar conclusions can be drawn in the Gas sector, with benefits being mainly derived by closer co-ordination between the gas distribution and gas transmission companies.

As we explain further in CSQ10 whilst we believe the most appropriate focus for RIIO-2 is for electricity distribution to electricity transmission, we suggest that the price control should enable the ability to consider the extent to which closer working between electricity and gas is necessary and addressing any barriers which may exist.

We are actively exploring the extent of whole system gas issues as we have reached out to the monopoly gas distribution operators in our area to understand any interactivities between their customers needs reflected in their RIIO-GD2 plans and those of our customers when we come to develop our ED2 plan. Work through the ENA on common reference scenarios is also informing our thinking as to the extent of cross fuel whole system issues.

CSQ10. Where might there be benefits through adopting a broader scope for some mechanisms? Please provide evidence.

We agree that in the longer-term the interaction across vectors, particularly gas to electricity, and potentially wider still will become increasingly important. Two key drivers will be as goverment policy on heat reaches a conclusion, and the decarbonisation of transport continues in order to meet the UK's carbon objectives. Whilst we see the decarbonisation of transport being primarily an electricity impact at present for passenger cars and vans, the decarbonisation of heat and the decarbonisation of larger goods vehicles brings both gas and electricity into play together. We also recognise that there may be benefits for the future regulation of heat to ensure ongoing consumer protection.

There is no doubt that these external impacts need to be factored in to companies' plans, and cannot be treated in isolation. Naturally other vectors have an impact on electricity and gas in terms of demand, growth and potential time of usage. Building these into the common reference scenario is a way of factoring these other vectors into companies plans without broadening the definition too much in the early days and therefore allowing companies to more organically evolve through innovation and the learnings of network to network working.

Either way the RIIO-2 price control does need to be flexible enough to allow companies the flexibility to enable changes which may not be at the pace or scale originally expected in order to deliver customer and stakeholders wants and needs and it is good to see this need for flexibility being recognised by Ofgem including by considering uncertainty mechanisms potentially with volume drivers.

Whilst we would expect to see work developing during the RIIO-2 period to investigate and develop the coordination and engagement in readiness, we feel that broadening scope beyond our narrow focus of Whole Electricity System would be unlikely to generate significant consumer benefits until the RIIO-3 start period of 2026 onwards.

The Open Networks project has set up workstream 4 as "Whole Energy System" in early 2019. We suggest this is the vehicle to investigate and establish activity to focus on where such a broader scope would provide benefits. The output of this workstream should help inform Ofgem's view of Whole System for the RIIO-2 period and consider which timelines/regulatory periods are most appropriate for broadening the definition wider.

CSQ11. Do you have reasons and evidence to support or reject any of the possible mechanisms outlined in this chapter? Do you have views on how they should be designed to protect the interests of consumers?

We have responded to questions CSQ11 to CSQ18 together.

CSQ12. Which of the possible mechanisms we have outlined above could pose regulatory risk, such as additionality payments or incentivising the wrong behaviour?

We have responded to questions CSQ11 to CSQ18 together.

CSQ13. Are there obstacles to transferring revenues between networks that disincentivise networks from using a coordinated solution (please give details and suggest any changes or solutions)?

We have responded to questions CSQ11 to CSQ18 together.

CSQ14. Can you recommend approaches that would better balance financial incentives between networks to enable whole system solutions?

We have responded to questions CSQ11 to CSQ18 together.

CSQ15. Are there other mechanisms that we have not identified that we should consider (please give details)?

We have responded to questions CSQ11 to CSQ18 together.

CSQ16. Are there any additional framework-level whole system barriers or unlocked benefits, and if so, any price control mechanisms to address these?

We have responded to questions CSQ11 to CSQ18 together.

CSQ17. Are there any sector specific whole system barriers or unlocked benefits, and if so, any sector-specific price control mechanisms to address these?

We have responded to questions CSQ11 to CSQ18 together.

CSQ18. Which of the proposed mechanisms would be most suitable in circumstances where a broader definition of whole system is likely to deliver benefits to network consumers?

We have responded to questions CSQ11 to CSQ18 together.

Possible Mechanisms

We fully agree with the established principle of incentivising companies for the benefit of customers and that these incentives should be fair and proportionate. Incentive mechanisms need to be fully aligned to customer needs.

Business plan incentive
As we explain in our response to CSQ65 we believe there continues to be merit in incentivising ambitious and cost effective business plans as this should be in customers' interests. However, we see some challenges in introducing a business plan incentive/penalty based on the strength of whole system thinking in the business plan.

Timing – there are two timing aspects to consider. The first is the practical aspect of tranche one companies' ability to comprehensively include whole system thinking within their business plans which are due for submission in December 2019, given the expected decision on definition is likely to be May 2019. There is limited time for customer and stakeholder engagement of the quality that will truly inform companies' plans and allow them to build in evidence-based benefits other than those already in train through existing processes. These are likely to lie in the Transmission/System Operator and DNO sphere driven through Open Networks and the NOA process. The second is the timing difference of electricity distribution to other sectors going through RIIO-2. It is likely to be difficult for Ofgem to ensure it can assess the strength of whole system thinking in a business plan, and consumer benefit, when a key corresponding geographic or vector network submits their plans two years later.

Role appropriateness – at a point in time where the transition to DSO continues to evolve and the Future Worlds direction of travel is yet to be decided upon, there is a risk that companies include in their business plan activities that may yet change and be concluded as appropriate to another parties role. This may be seen as a company or sector being ambitious to get on and deliver against a need whereas in fact it may ultimately not be in consumers' best interests because better whole system solutions may emerge, such as from ED stakeholder and consumer engagement and associated business plan development.

Competition versus collaboration – Business plan incentives can be an effective information revealing device, encourage ambition; and lead to companies presenting their most efficient and innovative view. This is generally done at a company level and by its nature has a competitive element which can be effective in generating benefits for customers. The overarching ethos on whole system thinking is collaboration and stakeholder engagement for overall consumer benefit, and is at odds with a competitive pot proposed for good plans under the business plan incentive.

We also consider how a business plan incentive specifically looking at whole system ambition can interact with the totex incentive mechanism and resulting sharing factor and ensure that if established the two are clearly indicated by Ofgem how they interact and are designed to compliment rather than conflict with each other, i.e. an ambitious whole system based plan may appear less efficient in cost assessment than other plans which may generate a business plan incentive for ambition, but may result in a lower overall sharing factor based on cost assessment. This risk may cause companies to be more cautious in their ambition in order to secure a higher percentage sharing factor.

With the above challenges in mind, we support a more "traditional" business plan incentive mechanism that assesses the full company business plan on all aspects and is not focused on one specific area. Companies undertake a breadth of activities, and many, such as faults or maintenance will remain a sizeable portion of companies costs, and have limited, if any, crossover into whole systems. This business plan incentive should be supported by clear guidance and assessment criteria.

Innovation
We provide more detail on our views on Innovation within our response to the questions in Chapter 8 (CSQ 44 to 64) however in summary whilst we agree that more innovation should take place as a

BAU activity we do not believe that developments through BAU will be sufficient to deliver the transformation likely to be required to facilitate the transition to the low carbon economy that our customers and stakeholders are indicating is a priority for them. Given the indication by Ofgem of RIIO-2 being a “tighter price control” companies are likely to need more incentives and funding to allow them to invest in research and development for benefits coming from a broader definition of whole system that may not result in benefits directly to them or to consumers within the regulatory time period.

Therefore whilst it is appropriate and indeed necessary that the innovation stimulus package allows for innovation projects with a whole system focus to be eligible for funding, we do have concerns that the overall innovation package should not restrict projects to only those aligned with selected strategic challenges. This could have a negative result of restricting the breadth of work being considered and may stifle innovation in other areas as new customer needs and potential solutions emerge.

Such innovation focus would need to be considered within the framework of the broader innovation stimulus package to ensure that such focus is complementary and provides companies with sufficient clarity and flexibility.

At present we expect the whole system opportunities to be greatest between electricity transmisison and electricity distribution activities. Therefore we consider separate gas and electricity innovation strategies continue to be appropriate at this time. However both these should include innovation to investigate potential whole system solutions between gas and electricity solutions.

Coordination and information sharing incentive

There are two funding elements associated with ensuring effective and beneficial coordination and information sharing.

The first is one-off set up costs which may be required to enable effective processes and systems. The benefits of establishing these could be substantial versus the potential loss of oportunity if not adequately funded. We suggest that companies incorporate any of these costs in their business plans and are funded under baseline allowances which we would expect to be incurred mainly in the early part of the price control period. This does leave a challenge for the electricity distribution sector who would not have the benefit of this until two years later than the other companies which in turn may cause misalignment and delays to benefits unlocking. Hence we propose a logging up mechanism is put into place for electricity distribution for 2021-2023 to ensure that the development of systems and processes needed to mirror ESO activities to deliver consumers benefits are not unecessarily delayed by the difference in price control start dates. The logging up process can be incorporated into the setting of the next price control for ED2 and can inform the development of enduring ED2 allowances.

We also support the principle that for business as usual coordination, this should be funded within baseline allowances, however recognise that new activities for DNOs as they evolve to DSOs and in turn create further opportunities for collaboration with transmission and the system operator as well as market flexibility procurement, that such systems and processes are adequately provided for within baseline allowances.

The second is as whole system solutions are considered more commonly during RIIO-2 there will be a necessary additional cost to companies for options assessment and feasibility studies that will lead to overall consumer benefit. At present it will be difficult to predict at what level and where the costs will fall for these activities and therefore an upfront allowance potentially combined with a mechanistic volume based funding driver for options analysis for a range of projects appear the two most relevant options presented within the consultation. We consider the project specific revenue stream less relevant.

It is important that the costs and any incentive is proportionate to the benefit potential for customers to justify such payments to companies however in principle we are supportive of these options and look forward to seeing these develop further.

We note that Ofgem refer to a minimum level of performance required before a symmetrical penalty is applied. We are cautious of the impact of applying a penalty regime into a new business area, and propose that for new activities such as these with potential sizeable consumer benefits an incentive only regime is more likely to generate the behaviours required than the application of a symmetrical incentive/penalty regime.

Balancing financial incentives between traditional and whole systems behaviour
We agree that the totex incentive mechanism is a significant incentive to ensure networks run their systems efficiently. Electricity North West continue to develop systems, processes and new options in order to embed whole system thinking within our operations, however accept that there may be the risk that the totex incentive mechanism alone may not be sufficient in fully ensuring whole system solutions are embedded into companies businesses.

By companies having different TIM percentages (sharing factors) and dependant on whether outputs lie in their or others price control, mean that relying on TIM alone may not be an appropriate way of ensuring whole system behaviour in RIIO-2. It is therefore important that these particular range of options are assessed to ensure that the entire RIIO-2 framework acts in a way to ensure balance and that sharing factor differentials don't create a risk of distortions to consumer outcomes. Having a clear whole system CBA approach used by both distribution and transmission companies is a way of addressing this concern about differential sharing factors because the CBA approach would provide a layer of governance and assurance as to which solutions go forward.

The options presented all merit consideration and taking each in turn:

<u>1 - Refining or formalising funding routes</u> – whilst the use of directly remunerated services can be used as a tactical solution for RIIO-1, we do not see this as a long term solution on its own for RIIO-2. However refining and formalising the routes is a postive step so we propose this is further investigated. Clarity on the appropriate use of BSUoS, TNUoS and DUoS is also required as the funding routes currently pre-determine which customers pay for what element of the electricity system. Transferring these across licensees bring this question to the fore.

<u>2 - Establishing mechanisms to redefine or transfer outputs between licensees</u> – it seems logical to apply the principle that the accountable party (in terms of licence obligation or traditional output owner) holds the funding, the output and therefore the risk. Should the licensee identify or have proposed to them an alternative method of delivery that provides a whole system solution, then the licensee should enter into appropriate arrangements with the delivery party to realise these benefits for consumers.

Transferring of funding and outputs may bring an unecessary layer of complexity, and therefore if this is to be considered for further development, it would need to be a more mechanistic process to allow discrete elements to be transferred, rather than a broader re-opening of aspects of the price control.

Equally, by transferring all the funding, there is no clear finanical incentive for the transferring party, and the delivering party, whilst now bearing the risk, also bears the opportunity for efficiency via

TIM which will also then be shared with their customers. Should this be a transfer from the SO or TO to the DNO, then consideration also needs to be given to the customers who will pay/share the benefits, as the difference between DUoS,TNUoS, BSUoS customers to be considered.

3 - Ensure regulatory incentives support beneficial outcomes – we see one of the principles missing in this section is the sharing of any outperformance to the enabling parties in order to truly incentivise companies to not only share information and coordinate, but to actively engage in seeking alternatives to deliver a planned or forecast need.

The Transmission System Operator working with the emerging Distribution System Operator functions is ideally placed to oversee decision making along with a layer of independent scrutiny as we proposed in the case of DNO/DSO decision making on load related reinforcements.

On balance it may be more practically effective to take a hybrid approach which is a combination of the first and third proposals and is described below.

A combination of the utilisation of DRS (or a similar concept) for the delivering company to ringfence costs and revenues, in conjunction with a sharing of an element of the efficiency outperformance would be an appropriate incentive, and mean a more equitable share of benefit for both the instigator and facilitator.

Illustrative Example:
Company holding funding and output – sharing factor 55%
Whole system solution identified and delivered by another licensee
Customer receives benefit of outperformance 45%
Holding company and delivering company share 55% equally

The other models considered may result in either one or the other company benefiting from the out-performance despite both companies collaborating to seek the optimal outcome for consumers.

Ensuring the framework is able to flex to meet whole system needs
There is no doubt that the RIIO-2 period has a range of uncertainties and whole system solutions are one of these known uncertainties. It is therefore appropriate that the price control is designed with this in mind and is flexible enough to address these as they arise.

Electricity North West are also mindful of the regulatory burden that this may entail, particularly as the price controls for electricity distribution start at a different time to the other RIIO-2 companies, and the ESO is proposed to have a 2 year cycle with a 5 year planning horizon. There is a risk that both companies and Ofgem are in a perpetual round of reopeners and price control processes. Volume drivers may be an alternative solution in some cases, however a more permanent option to be explored for future price controls would be to consider alignment of electricity distribution to the other network companies in due course and particularly electricity transmission at the next opportunity.

We propose that flexibility is built into the price control where appropriate, and expenditure that may be facilitated elsewhere is not locked in so that customers can benefit from solutions available at the point of decision making. The proposals in balancing financial incentives does bring the risk that companies may forecast traditional solutions for all known projects, and when whole system solutions may be identified in period, companies gain the benefit, along with customers through TIM.

For projects not identified in companies business plans that arise in period, a coordinated reopener is appropriate. There are arguments for different windows due to companies price control start dates, however it is highly likely that whole system solutions will generally cross either the distribution or transmission boundary and therefore a reopener at the start of RIIO-ED2 and the start of RIIO-3 are the most appropriate times, ie 2023 and 2026. At the time of setting price controls, these solutions should be automatically incorporated into companies business plans. Materiality for reopeners whilst in place for good reason are sometimes a challenge, and may need to be considered in this specific case to be reduced in order to prevent deferral to the next business plan cycle due to the materiality and regulatory burden involved in submitting a reopener.

A more mechanistic funding mechanism could also be explored, for example where there is a known business need, but also a known potential alternative form of delivery so that this can be more mechanistically delivered without the need for a reopener. Eg reactors to manage voltage levels – we know we will need to deliver x, but x may be delivered by the DNO.

Whole system discretionary funding mechanism

The use of the words discretionary funding has caused a little confusion over the intention of this option, as the description implies discretionary funding as a reward, as opposed to how it is explained which is for delivery of projects which emerge during the price control which were not originally factored into companies plans.

It is unclear how this, reopeners, transfer of outputs and innovation funding all may interact with each other, or whether they are stand alone either/or options.

We consider that appropriately designed uncertainty mechanisms (including reopeners), together with balance of incentives should be adequate, and that no further discretionary funding mechanism is required.

6 Ensuring future resilience

CSQ19. Do you agree with our proposals to use monetised risk as the primary basis for network companies to justify their investment proposals for their asset management activities?

We agree with this approach, although suggest that Ofgem need to be mindful of the relatively limited scope to which the monetised risk approach applies in some sectors. As noted in the document (section 6.22), asset management works outside the scope of NARMs will need to be subject to separate funding, assessment and output arrangements.

We also suggest that Ofgem should be cautious in making monetised risk comparisons across sectors as we are aware that the associated risk methodologies differ significantly in their detail.

CSQ20. Do you agree with our proposals to define outputs for all sectors using a relative measure of risk?

Ofgem's proposals are not sufficiently clear to us as set out in this consultation. Drawing on wider discussion we are assuming that a 'relative' measure of risk refers to the amount of risk reduction over the five years of the price control occurring as a direct result of qualifying interventions for a given funding level, then we agree with this proposal as it ties the quantified output (i.e. volume of risk reduction delivered in 5 years) more closely to the associated allowances.

CSQ21. Do you agree with our proposals for defining outputs using a long-term measure of the monetised risk benefit delivered through companies' investments?

We suggest this proposal needs careful consideration and is fraught with complexity. We agree that investment proposals need to be assessed in the context of their long-term benefit, and this is what the CBA model attempts to facilitate. However, there will need to be careful assessment on a sector-specific basis as to the extent that the monetised risk approach and CBA model are consistently calibrated against each other. We understand that this is not the case for the GD & T sectors, and that this will require further work for ED ahead of the ED2 control.

The implication of the proposal is that each component of the NARMs plan will effectively be subjected to a CBA. We would welcome further clarification from Ofgem as to the level at which they see the CBA approach being applied within RIIO2 as we have previously understood that Ofgem wish to simplify the CBA requirements.

Clear guidance will be required as to how to calculate the lifetime value, against what baseline assumption and over what period amongst other things. Benefits would also need to be measured at the point of intervention and not subjected to hindsight assessment. This guidance will need to be provided early in the process ahead of business plans being developed to avoid rework of investment planning and repeats of customer and stakeholder engagement.

CSQ22. Do you agree with our proposed approach to setting allowances and outputs?

We generally support the proposals, although we note that NARMs is a relatively narrow interpretation of asset 'resilience' and that appropriate consideration will also need to be made of resilience to extreme events such as flooding, storms, Black Start. We do not believe Ofgem has considered these aspects in its proposals to date.

We also note that willingness-to-pay is frequently difficult to ascertain with regard to a relatively abstract non-service measure such as monetised risk.

Any benchmarking across licensees in this area will be dependent on 1) a consistent application of NARMs scope, 2) appropriate consideration of qualifying expenditure and 3) consideration of risk factors outside of the NARMs methodology. These will all need to be reviewed ahead of ED2.

CSQ23. Do you have views on the proposed options for the funding of work programme spanning across price control periods?

We are concerned that this could become a very complex area, in the face of Ofgem's drive for simplicity. We need to see more detailed specific options though we already consider the existing High Value Project (HVP) mechanism covers off much of this risk adequately for ED2 and should be retained, subject to a discussion on appropriate qualifying thresholds and confirmation of the proposed ED1 Closeout arrangements in this regard.

CSQ24. Do you have any views on the options and proposals for dealing with deviation of delivery from output targets?

We are concerned that under-delivery is assumed to be punitive, unless a company can prove to the otherwise. Whilst we agree that the risk targets should be set on a relative basis, their achievement should be reviewed cognisant of changes in the overall risk position (e.g. through the impact of other investment, changes in data), otherwise a licensee may be incentivised to deliver outputs no longer required due to the potential consequences of punitive action.

Similarly, we suggest that over-delivery should not be unfairly penalised, particularly if considered in the context of overall allowance outperformance.

In both cases, an appropriate dead band will be required to ensure that complex closeout processes are not required for minor variations against target. These closeout processes also must be defined from the outset of the price controls.

CSQ25. Do you have any views on the interaction of the NARM mechanism with other funding mechanisms?

We believe that these arrangements may work adequately in the current ED context, however this relies on robust definitions of qualifying and non-qualifying expenditure. Further work will be needed to develop any ED approach as part of that price control development.

We propose adjusting the current expenditure categorisation to more clearly differentiate that expenditure incurred on assets qualifying under NARMs, and also to more clearly credit interventions primarily aimed at mitigating the consequence of failure, as opposed to the probability (i.e. replacement and refurbishment). This should build on any work in this regard completed as part of the RIIO-ED1 Closeout process.

CSQ26. Do you have any views on ring-fencing of certain projects and activities with separate funding and PCDs? Do you have any views on the type of project or activity that might be ring-fenced for these purposes?

The ring-fencing of qualifying activity and expenditure for NARMs appears to work well in ED1. There is a well-established practice through the RIGs of reporting all risk movements and only crediting the appropriate qualifying ones towards achievement of the NARMs target.

The High Value Project (HVP) mechanism is an appropriate way of ring-fencing large projects and removing their potentially distorting effect from an overall NARMs measure. This mechanism also allows for the definition of an appropriate Price Control Deliverable for the project.

CSQ27. Where companies include a sustainable workforce strategy as part of their business plans, what measures do you think could be established to hold companies to account for delivering these plans, without distorting optimal resourcing decisions?

We recognise the benefits of companies including a sustainable workforce strategy within the Business Plans, although think further clarity is required in terms of what this should include as it is currently not defined either within the Consultation document or in the Business Plan Guidance that has recently been consulted upon.

We are sharing some initial thoughts on what a sustainable workforce strategy for ENWL as a DNO will need to reflect. These factors such as the changing demands on the business as it facilitates the transition to a low carbon economy, including the requirements that emerge from the development of the DSO model and factors like changes in attrition rates as colleagues seek to move more within and beyond the sector may be relevant for transmission and gas distribution.

Based on our knowledge, it is difficult to specify a range of measures at this time that could be used to hold companies to account. We therefore suggest that a requirement to report on progress against the strategy as part of consolidated annual reporting to Ofgem and to our customers and stakeholders seems to be the most appropriate approach, whilst recognising that this will evolve during the ED2 period. Given Ofgem’s proposals to reduce the number of incentives, we are unsure what is envisaged by the reference to an incentive is within para 6.64.

CSQ28. Do you agree with maintaining the existing scope of costs that fall under Physical Security, ie costs associated with the PSUP works mandated by government? Please explain your reasons and suggest alternative definitions you believe should be considered.

We agree with this proposal.

CSQ29. Do you agree with our proposed approach of ex ante allowances for PSUP works mandated by government? Please explain your reasons and suggest alternative approaches you believe should be considered.

We agree with this proposal, as these costs should be reasonably foreseeable for those qualifying sites known at the time of submission.

CSQ30. Do you agree with our proposal to include a reopener mechanism to deal with costs associated with changes in investment required due to government-mandated changes to the PSUP?

We agree with this proposal as our experience is that these requirements have changed a number of times previously and could potentially expose licensees to significant additional costs within period, particularly if the associated compliance dates also fall within the period. In line with the approach adopted for ED1, we would expect there to be a low, if not zero, materiality threshold applied to a reopener of this nature as it is outside the scope of control for network companies.

Conversely, we would expect that any sites for which funding has been secured that are subsequently removed by government would be subject to a return of allowances under a reopener.

CSQ31. We would also welcome views on the frequency that is required for any reopener, eg should there be one window for applications during RIIO-2 and, if so, when?

We suggest that there is a combined window for all licensees around the middle of the combined RIIO-2 period (i.e. 2021-2028), in 2025. This would allow for a single re-opener across all sectors which would be particularly useful in the context of sites shared between TOs and DNOs.

CSQ32. Do you agree with the scope of costs that are proposed to fall under cyber resilience, ie costs for cyber resilience which are (1) incurred as a direct result of the introduction of the NIS Regulations, and (2) above 'business-as-usual' activities? Please explain your reasons and suggest further or alternative costs you believe should be considered.

This is a reasonable starting proposal but further work will be needed on the associated definitions which must be workable. We wish to continue working with Ofgem to understand the implications for ENWL and our customers.

CSQ33. Do you agree with our proposed approach of ex ante 'use-it or lose-it' allowances? Please explain your reasons and suggest alternative approaches you believe should be considered.

This appears appropriate but suggest that more clarity is needed about what would / would not be included within the scope of the allowances.

CSQ34. Do you agree with our proposal to include a re-opener mechanism for cyber resilience costs? Please also provide your views on the design of the re-opener mechanism.

We agree with this approach which should cover big ticket items or where costs are sufficiently uncertain. We suggest that the current materiality threshold is probably too high and should be reviewed for this area. A mid-point reassessment may be useful as technology is moving at a rapid pace in this area.

7 Managing uncertainty

CSQ35. Do you have any views on our proposed factors to consider in deciding on appropriate input price indices? Do you have any evidence justifying the need for RPEs and any initial views on appropriate price indices?

We have responded to questions CSQ35, CSQ36, CSQ37 and CSQ38 together.

CSQ36. Do you agree with our initial views to retain notional cost structures in RIIO-2, where this is an option?

We have responded to questions CSQ35, CSQ36, CSQ37 and CSQ38 together.

CSQ37. Do you agree with our initial views to update allowances for RPEs annually and to include a forecast of RPEs in allowances? Do you have any other comments on the implementation of RPE indexation?

We have responded to questions CSQ35, CSQ36, CSQ37 and CSQ38 together.

CSQ38. Do you agree with our proposal to use the EU KLEMS dataset to assess UK productivity trends? What other sources of evidence could we use?

We have responded to questions CSQ35, CSQ36, CSQ37 and CSQ38 together.

There appears to be some logic in Ofgem's current proposal. However, given the scope for potential changes in this area over the coming years, we anticipate more detailed consideration being given to the treatment for real price effects and similar measures as part of the ED discussion.

CSQ39. Do you think there is a need for a utilisation incentive at the sectoral level? If so, how do you think the incentive would operate coherently with the proposed RIIO-2 price control framework for that sector?

The current use of operating demands in electricity distribution networks is based on the principle that an asset operates at its peak capability for a period of time whilst the majority of times the asset is operating below its maximum operating capability. The cycle of heating and cooling of assets is a recognised characteristic and means that the maximum operating capability is higher than a continuous rating due to latency of the asset. There are very few assets in the distribution network where the utilisation is 100% i.e. it is used at its capability continuous through time. Where this occurs, the peak demand that an asset is capable of operating at is limited as the thermal latency of an asset can be used in defining its operating regime. In most cases, the operating demands on our distribution network assets are utilised at around 50% to 60% (of its capability) and therefore there is significant available distribution network capacity for customers to use. Our Capacity to Customers project showed the potential for much of this capacity to be used by customers willing to enter into flexible contracts. This has now become the normal operating regime for much of the network where assets are operating close to capacity.

Where additional capacity is needed, we consider a capacity uncertainty mechanism would be more appropriate than a utilisation incentive. For example, whilst DNOs can aim to maximise the use of assets, ultimately customers choose where to connect and under what terms. Addressing the inherent uncertainty is more material than a notional asset usage metric. Such a mechanism could require the network operator to publish available capacity metrics, persuade customers, through tariffs, to make use of this available capacity and to publish utilisation metrics for key assets. However once capacity is used, efficient creation of additional capacity is essential. This type of mechanism complements the totex incentive mechanism as, instead of proposing to develop the network or fund flexible services to mitigate bespoke reinforcement needs, it drives the network operator to shift demand and/or generation to use the network when there is available capacity. It does not drive opposite behaviours for asset health indices, but close monitoring of operating regimes and asset health indices would be required to ensure that the quality of service standards to customers are maintained, not reduced. We trust these insights from a distribution perspective are useful.

CSQ40. Do you have any views on our direction of travel with regard to anticipatory investment?

We are supportive of your proposals to require additional evidence to be gathered for any anticipatory investments. In RIIO-ED1, we have introduced into business as usual an evaluation process for all investments; this process, defined as our Real Options Costs and Benefit Analysis

(ROCBA) approach, was developed under a NIA project and it evaluates traditional and alternative solutions, including market solutions like demand side response or flexible services, against a backdrop of our five demand scenarios (also developed as part of a NIA project, called ATLAS). Our journey to develop this into a probabilistic CBA will involve creating the necessary functionality in preparation for RIIO2. We do believe that robust planning coupled with such a probabilistic real options evaluation approach can ensure efficient delivery of capacity (via DSR or assets) just in time for customer needs.

When considering proposals for anticipatory investment, we expect Ofgem to consider the extent to which such proposals have been shaped and challenged by customers, as well as local and regional stakeholders, and views from the Customer Engagement Group or User Group on these proposals. This approach will ensure that network companies are well placed to facilitate growth aspirations at a regional level, whilst ensuring plans are within the bounds of that which customers are prepared to support.

CSQ41. What type of projects may be appropriate for a risk-sharing approach?

When developed and utilised properly, a probabilistic CBA may reduce the need for all but the most highly anticipatory investments because the probabilistic CBA will assess the uncertainty risk and give a proposed investment decision. There are strong drivers in the RIIO framework, through the various incentive mechanisms, that limit the opportunity for truly anticipatory investments. Where an investment is highly uncertain the CBA should propose the option of delaying or taking the first least regrets step. The issue of timing is the key determinant – there are two examples that highlight this timing issue; a large network development takes several years to deliver and so we have to start work prior to the uncertainty reducing to an acceptable level so it is delivered in time; and the second case is where a widespread change, through lots of small interventions, is anticipated over multiple years and in multiple locations which could not be delivered when required if all work was left until the need was certain. In both cases this can be managed through a least regrets approach within a CBA. Therefore Electricity North West is not convinced there is a need for developing a risk sharing approach for anticipatory investments.

CSQ42. How can we best facilitate risk-sharing approaches for high-value anticipatory investments?

We have answered questions CSQ42 and CSQ43 together.

CSQ43 How can we guard against network companies proposing risk-sharing arrangements for project they may have undertaken as business as usual?

We have answered questions CSQ42 and CSQ43 together.

In the event that a high-value anticipatory investment was being developed, we expect Ofgem to have a significant level of oversight of such a project through a mechanism like Strategic Wider Works or companies regulatory reporting mechanisms as to the approaches being developed to compete projects of a high-value or similar. As such, we believe it is likely to be appropriate for any variation to the standard risk-sharing approach to be developed as part of this interaction and specific to the project in question, rather than as part of the RIIO-2 Framework.

8 Driving innovation and efficiency through competition

CSQ44. Do you agree with our proposals to encourage more innovation as BAU?

Electricity North West agrees that more innovation should take place as a BAU activity. An appropriately set totex incentive mechanism should drive network operators to seek opportunities for incremental innovative improvements that streamline existing approaches, delivering benefits for customers, stakeholders and shareholders. This is particularly true for developments with high Technology Readiness Levels (TRLs). We consider that if network companies are certain that a project will work then it cannot really be regarded as innovation.

However, we do not believe that developments through BAU will be sufficient to deliver the transformation likely to be required to facilitate the transition to the low carbon economy that our customers and stakeholders are indicating is a priority for them. The level of change required for electricity distribution carries with it a level of risk that contrasts with the low risk framework Ofgem has indicated that it is seeking to implement for RIIO-2. As such, mechanisms will continue to be required to enable DNOs to trial solutions to respond to these challenges as they arise.

RIIO-1 innovation stimulus recognises that not all innovation will be successful, indeed the recent history of projects funded through this framework demonstrate that important lessons can be learned from these failures. We are concerned that the proposed changes will result in projects, particularly those anticipated to deliver operational and maintenance improvements, might not be funded, especially where there is a high level of uncertainty of success.

There is also a further risk in pushing innovation to BAU that the current dissemination requirements would then not apply. The current approach means that all customers have the potential to benefit from innovative improvements. However, a more limited regime has the potential for improvements which could benefit all customers being retained by individual network operators for commercial advantage, especially in the event of intensified competition through relative and/or reputational incentives being introduced.

CSQ45. Do you agree with our proposals to remove the IRM for RIIO-2?

It is finely balanced whether or not it is appropriate to remove the IRM for RIIO-2. In a shorter period, we see reduced requirement for a mechanism of this nature and we recognise the relatively limited use made of the mechanism during the longer RIIO-1 period. However, given the transformative change facing the electricity distribution sector, it is possible that unanticipated disruptive technologies may become available during the period that cannot be funded through other mechanisms. Maintaining some flexibility to allow network companies to respond to such developments could be beneficial to avoid the need to delay adoption until RIIO-3. Especially as including the IRM in RIIO-2 is relatively low regulatory burden since it has been developed and already implemented in RIIO-1 therefore both companies and Ofgem have experience of it. Even though it hasn’t been used that often in RIIO-1 to date, we believe IRM has generated substantial consumer benefit against the cost of operating it though this would be something relevant for Ofgem to assess before taking a decision on the future of this mechanism.

CSQ46. Do you agree with our proposals to introduce a new network innovation funding pot, in place of the Network Innovation Competition, that will have a sharper focus on strategic energy system transition challenges?

Electricity North West has concerns restricting projects to those aligned with selected strategic challenges may stifle innovation and restrict the breadth of work being progressed that may limit potential responses to the complex and rapidly evolving transition. The proposed narrow, more focussed approach has the potential to increase coordination but will ultimately prevent groundbreaking innovation from receiving funding. This concern is supported by our experience from the latest joint call for NIC ideas, which has highlighted a diverse number of projects worthy of funding, and there is a risk that this approach could be lost in RIIO-2. Whilst we recognise that the strategic challenge will be reviewed on a regular basis, this may not be sufficient to outweigh the potential consumer detriment.

We believe NIC projects already demonstrate a high level of collaboration with third parties and Electricity North West is currently actively engaged with a number of DNOs delivering on these projects. Whilst we recognise the wider benefits of the collaborative approach advocated by Ofgem, there are challenges at present for multi licensee projects, principally that current governance requires one network company to lead a project, which effectively relegates any others to project support.

We support splitting projects by stage gating them to enable early-stage research and development (limited deployment, prior to later-stage demonstration and deployment trials) but are concerned that this could result in a large amount of early stage research, paid for by our customers with little resultant customer benefit.

CSQ47. Do you have any views on our proposals for raising innovation funds?

The proposals for raising innovation funds for transmission and gas distribution seem appropriate.

CSQ48. Do you think there is a continued need for the NIA within RIIO-2? In consultation responses, we would welcome information about what projects NIA may be used to fund, why these could not be funded through totex allowances and what the benefits of these projects would be.

We believe that there is still a need for the NIA to allow Research & Development of higher risk ideas on a smaller scale/size. In our experience, lots of solutions have been developed using this funding and its predecessor (IFI), that would not have otherwise been developed as the potential to deliver shareholder value was insufficient or unclear at the onset of the work. However, we recognise that there is potential to further enhance the NIA approach going forward.

ENWL has a proven track record of transitioning NIA projects into BAU, when solutions have been proven and there is a customer or network need for them. Withdrawing this funding may have a number of unintended consequences which are not in customers' interests such as network operators only progressing innovation projects where they are (almost) guaranteed to succeed and a BAU need currently exists. This short-term focus is unlikely to support the transition to a low carbon economy that we anticipate being required in the longer-term.

At present, NIA funding is allowing us to build a portfolio of options to resolve expected challenges, driven by emerging customer need and the low carbon agenda (e.g. high uptake and clustering of

LCTs). We strongly believe that it is a substantially more expensive path and materially higher risk to reactively investigate emerging issues and network constraints as they appear. In electricity distribution, the current framework is facilitating the development of a range of tools that the DNOs can utilise, as an alternative to traditional reinforcement, as and when network and customer need dictates. The deployment of new technical and commercial initiatives, based on the learning outcomes of NIA / IFI / LCNF demonstrates the success of the current framework. We anticipate BAU transition will increase over the next 5-10 years driving even more benefit for consumers.

The value of NIA funding needs further consideration. Currently, it is a small percentage of totex which, for larger groups, can create significant potential funds. However, unlike deployment of new technologies, forecast totex spend is not necessarily the most appropriate measure for innovativeness. We suggest it may be more appropriate to equalise NIA between groups within a sector, rather than on a licensee basis. As the benefits of this innovation should be shared through effective knowledge dissemination, we suggest that it may be appropriate to also share the costs. Additionally, in a low risk and low return regime the 10% compulsory network company cost contribution should not be increased, and there may be a case to lower it in a tougher regime if innovation is to continue at current or greater intensity.

Based on our experience, a significant proportion of the current NIA funding goes to small to medium enterprises (SMEs) to help develop solutions for network companies. This funding has resulted in the development of a number of truly innovative new products, which have now been embedded as proven technology into BAU, and are delivering significant network and customer benefits. Some of these products were developed as a direct result of a specific problem identified by the network companies. The success of initiatives developed under this funding mechanism is demonstrated by technologies that have been adopted by DNOs across GB. One such example is the Kelvatek Bidoyng or ‘smart fuse’ for managing transient faults, which was developed further in Smart Street to provide remote LV interconnectivity for voltage management. These devices have transformed the experience of customers during transient faults. This funding is also vital for engaging effectively with SMEs who are driven by external market conditions. As NIA has a lower level of governance than the NIC and is not subject to bid costs, which can prove prohibitive for technology developers, the funding provides an effective mechanism for enabling third party involvement. However, we do think it is important that the NIA governance is clarified so that BAU deployment of solutions previously tested using NIC or equivalent funding is not then funded as part of NIA projects.

The issue of potential unnecessary duplication of projects has been resolved by the ENA process that enables all network operators to review, comment and challenge pre-registered NIA projects. The multi-DNO process also enables learning from other projects to be highlighted and incorporated in new projects to build on learning. We believe that the involvement of third parties in NIA projects is already very strong so we are surprised that it is felt that this needs to be strengthened further. We believe that our role is to act as a ‘gatekeeper’ to make sure that customer funding is spent wisely but to also to act as an enabler.

CSQ49. If we were to retain the NIA, what measures could be introduced to better track the benefits delivered?

We believe that all closed NIA projects should be reviewed in the annual NIA report for a period of three years following closedown to highlight transition into BAU or NIC research. This approach would provide a suitable mechanism to disseminate cost savings delivered by the project and the longer term benefits derived from the research.

It should be noted that some research projects do not deliver totex benefits but deliver benefits such as reduced connection cost, quicker connection times, environmental and carbon benefits as well as improving forecasting and investment plans. These benefits can be more difficult to track but are valid and improve the customer experience. To allow tracking of benefits such as connection costs and times would mean the Network Operators have to quantify the counter factual which can be time consuming and could mean maintaining old systems which could negate the benefit accrued by the customer. These benefits would be better tracked through direct engagement with Ofgem on a yearly basis to present the NIA portfolio to highlight the progress, strategy and benefits of the entire portfolio.

CSQ50. Do you agree with our proposals for electricity distribution companies prior to the commencement of RIIO-ED2?

We agree with the proposals for the electricity distribution companies prior to the commencement of RIIO-ED2 subject to our comments above.

CSQ51. Have we set out an appropriate set of models for both late and early competition to explore further?

As set out in previous responses, Electricity North West supports the use of competition where it can be shown to be in the best interests of our customers. To date, we have demonstrated our commitment to competition through our approach to opening up the greatest number of connections market segments to competition, introducing tenders for the provision of flexibility services and work to develop a platform to enable market participants to trade network capacity. We have also proactively engaged with Ofgem on its development of the CATO approach, even though not directly applicable to electricity distribution.

The models set out provide for a range of situations where it may be appropriate to consider the use of competition. We recommend that these should not be seen as a definitive set of models as the development of new approaches may allow alternatives to be brought forward that may be more effective in delivering benefits for customers.

CSQ52. Do you agree with the proposed criteria we have set out for assessing the suitability of late competition models? Would you suggest any other criteria, and if so, why?

As set out in our previous responses, the criteria of ‘new’, ‘separable’ and ‘high value’ continue to be appropriate, although we note that these have been developed in relation to electricity transmission and suggest further work may be appropriate to consider the opportunities, and then associated benefits and costs of applying the same approach to other sectors.

CSQ53. Do you have any views on the costs and benefits we have used for our draft impact assessment on late competition?

We note that the benefits being drawn on within the draft impact assessment are drawn from transmission and may not appropriate for other sectors, especially electricity distribution where, for slow-track companies, there is already a lower cost of capital than other sectors. The counterfactual, including the expected cost of capital, will need updating in assessing the benefits and costs of late competition given the emerging shape of RIIO-2 proposals and some of Ofgems "working assumptions" on financial parameters. Similarly, in sectors like electricity distribution where contestability of connections is well established, there may be less scope to derive benefits than in other sectors.

CSQ54. Are there any considerations for a specific sector we should include in our IA?

We are not aware of any for transmission or gas distribution.

We note that Ofgem intends to develop the framework for electricity distribution at a later date. We suggest that, given other work that is currently ongoing in electricity distribution to introduce additional forms of competition such as the opening of flexibility markets as an alternative to building network assets and work being undertaken as part of the Open Networks projects, considerations for electricity distribution may differ significantly from other sectors.

CSQ55. What are your views on the potential issues we have raised in relation to early competition? How would you propose mitigating any issues and why? Are there additional issues you would raise?

We have answered questions CSQ55, 56, 57 and 58 together.

CSQ56. Are there other potential drawbacks of early competition?

We have answered questions CSQ55, 56, 57 and 58 together.

CSQ57. Do you consider that there are any existing examples of early competition (including international examples or examples from other sectors) which demonstrate models of early competition that could generate consumer benefit in the GB context?

We have answered questions CSQ55, 56, 57 and 58 together.

CSQ58. What are your views on the advantages and disadvantages of the high-level approaches to early competition outlined? How would you recommend mitigating any disadvantages?

We have answered questions CSQ55, 56, 57 and 58 together.

We agree with the challenges identified in Appendix 2 in relation to early competition, namely Deliverability, Access to land and Change in circumstances. When considering opportunities for early competition, the challenge will be in streamlining the process to avoid every competition being 'bespoke' like the work on the Shetland New Energy Solution, and thereby minimising the costs associated with running the competition and awarding to the successful participant.

However, the emerging use of flexibility tenders within electricity distribution demonstrates that there are opportunities to introduce early competition in a cost effective way that deliver value to end customers and also open up new opportunities for participation by both new and existing market participants. It is important that these tenders are given time to evolve organically to meet the needs of the all involved.

CSQ59. Do you have any views on the potential criteria for identifying projects for early competition discussed above? Would you suggest any other criteria, and if so, why?

We believe the criteria of ‘new’ and ‘separable’ and ‘high value’ are likely to be appropriate for identifying early competition projects that require the involvement of the system operator or Ofgem to establish them. In these instances, we believe experienced network operators will have a view of whether the counterfactual investment to respond to a given need is likely to trigger these criteria and therefore whether it may be appropriate to apply an early competition approach.

We note that network operators, including DSOs, may identify other opportunities for competition and opportunity should be given for such opportunities to evolve organically as needs and solutions prevail where these can be shown to deliver value for customers.

CSQ60. Do you agree with the criteria we have set out for assessing who should run competitions? Based on these criteria, which institution do you consider is best placed to run early and late competitions?

The ability to understand the identified need and proposed solutions to it is, we believe, the most important criteria for who is best placed to run competitions. For very large projects such as Strategic Wider Works, there is merit in Ofgem assessing potential bids with the support of technical consultants. However, for smaller projects, we do not believe this is the most efficient approach.

In our opinion, network companies are best placed to understand the needs arising within their area and scrutinise proposed solutions. However, we do recognise that there is the potential for a perceived conflict of risk with this approach. For this reason, we advocate the role of an independent body, such as a Customer Engagement Group, to challenge and scrutinise the decision-making process to be able to reassure all parties that any potential bias, perceived or otherwise, is effectively and appropriately managed to deliver cost-efficient and effective solutions for customers.

CSQ61. Do you agree with how we have described native competition? Do you agree we should explore the proposals described above to enhance the use of native competition? Are there any other aspects we should consider?

We believe native competition should be defined as ‘competitions that are run by a network licensee’. We do not believe it is appropriate to limit these to being a response to the totex incentive as there may be a wide range of reasons which result in a similar outcome, i.e. a network company running a competitive process to deliver an effective and efficient outcome. We believe that such native competition is in the best interests of customers and should therefore be welcomed and encouraged.

Network companies are experienced in running competitive processes as part of procurement activity so are well placed to run such competitions and the broadening out of this thinking to seeking solutions to identified needs is a logical development of this expertise. It also reflects the changing needs of network companies as focus shifts to making flexible capacity available to support the transition to a low carbon economy.

CSQ62. How do you think competition undertaken by network companies should be incentivised? Is the use of totex the best approach? Will this ensure a level playing field between network and non-network solutions including the deployment of flexibility services?

We believe that totex continues to be the most appropriate approach to incentivising network companies to consider a wide range of potential solutions to the challenges they face. We believe this does create a level playing field for network and non-network solutions.

Ofgem needs to be mindful that its proposals with regard to blended sharing factors do not inadvertently dampen this incentive.

CSQ63. What views do you have on an approach where totex allowances would be based on costs revealed through competition, with a margin or fee for the competition-running entity?

We are unconvinced that this approach is needed for the RIIO-2 period and that network companies should instead be encouraged to expand the approach currently being utilised in ED1 to run competitions for flexibility contracts and alternative solutions to building assets.

CSQ64. Do you think the ESO could have a role to play in facilitating competition in the gas sectors?

We are unconvinced that there is a role for the ESO to facilitate competition in the gas sectors and suggest further work is required to consider whether or not such a role is required and whether the ESO is best placed to discharge this.

9 Simplifying business plan assessment

CSQ65. What are your views on our proposed approach to establishing a business plan incentive?

We believe there continues to be merit in incentivising ambitious and cost effective business plans as this should be in customers' interests. However, we do have some concerns with the proposals as included in the consultation document.

1. Compliance check – in order for this to be appropriate, the Business Plan Guidance needs to clearly set out what companies need to do to be able to pass this hurdle. At present, the Guidance is still not finalised and subjective in areas, making it very difficult for companies to be able to satisfy themselves that they have acted in accordance with it. As not passing this stage could trigger an upfront penalty, we do not believe this is appropriate.
2. Evaluation of quality – similar to the comments on the compliance check, we do not believe the Business Plan Guidance is sufficiently clear to allow companies to understand Ofgem's expectations with regard to what constitutes quality. A considerable amount of work goes in to compiling a price control business plan and we certainly seek to ensure our plans are challenging and of a high quality. Lack of clarity regarding expectations increases the level of risk associated with compiling these plans which we do not believe is in customers' interests.
3. Competitive element to the reward – we do not support this. We have no way of knowing the approach adopted by other parties and do not think this is helpful. It is likely to deter companies sharing thinking on aspects of plans that would benefit from collaboration. We

also do not see that there is detriment in a high number of companies submitting plans deemed to be Good Value and being rewarded for this as this should ultimately drive benefits for the customers of the respective plans, particularly in sectors like electricity distribution where costs are not socialised so the customers funding any reward would be those directly benefitting from the more stretching plans. Plans should also not be forced into a ranking for a reward but should be assessed and rewarded independently of each other.

CSQ66. Under the blended sharing factor approach, should the scope of stage 2 evaluation of cost assessment be based on the entire totex or only on cost items that we consider we can baseline with high confidence?

We do not believe it is necessary to distinguish between cost categories for the cost assessment element of a Business Plan Incentive. Companies will need to justify their costs and to determine the most appropriate mechanism to fund these. Where costs are uncertain, it may be appropriate that some form of uncertainty mechanism is used, either to allow these to be considered within or after the period (for high levels of cost uncertainty) or by some form of volume driver (for high levels of volume uncertainty). The approach taken to determining costs and how these should be funded should be evaluated, rather than just focusing on the actual costs themselves. Consideration just of the costs themselves may miss the bigger picture of the approach being taken by a company.

CSQ67. What should be the method for categorising cost forecast as High, Medium or Low? Are the indicative boundaries of 1.0 (High to Medium) and 1.04 (Medium to Low) appropriate?

At a high level, the method seems appropriate but we believe this needs to be reviewed for electricity distribution as the policy for this sector develops. Much more detail needs to be developed and provided including Ofgem sharing more on how its proposed boundaries were set.

CSQ68. What should be the range for the business plan reward/penalty? Is the range of ±2% of totex equivalent appropriate for incentivising high quality and ambitious business plan submissions (eg Value or Good Value)?

In line with Ofgem's statements elsewhere in the consultation document, namely to "*apply financial rewards mainly where the overall cost of the incentive does not exceed the value of improvements to consumers, and where performance improvements are not already funded through the baseline*" (para 4.24). The costs of compiling business plans is significant and most companies will have only included a fraction of the costs for developing RIIO-2 plans within their RIIO-1 Business Plan, as a consequence of expectations being less developed when these plans were submitted. Accordingly, the incentive should be calibrated against the potential additional costs licensees will incur to deliver plans of the level of quality and ambition expected.

The consultation is unclear as to what the ±2% of totex equivalent equates to. We assume based on previous controls that this is total totex across the whole price control but note that Ofgem has mooted the possibility of it being related to only a single year's allowance. There is obviously a big difference between these two. Clarity on this point is needed.

We are also unclear whether this should be a percentage of totex by licensee, a fixed level per Group or a hybrid of these. For ED1, Groups of licensees within the same ownership were able to submit combined plans for their multiple licensees. The incremental costs per additional licensee is significantly reduced if this approach is adopted, whilst there is a significant level of fixed costs that are applicable whether the submission covers one or four licensees. As such, we believe that, in the event, Ofgem permits Groups to submit combined plans then either an absolute cap on the potential reward for Groups should be applied or an uplift made available for licensees who are not part of such Groups.

CSQ69. Do you agree with our assessment of the IQI? (if not please provide your reasons). Do you agree with our proposal to remove the IQI?

In our previous responses, we have expressed our concerns with the IQI, which are not necessarily the same as Ofgem's. As previously stated, we are concerned that the IQI matrix did not adequately reward companies for efficient business plans in ED1 and the application in RIIO-1 was with errors. As such, we do support the proposal to remove the IQI.

In developing its successor, we believe it is important that licensees should be rewarded for developing challenging and realistic plans that also demonstrate the characteristics of being stakeholder-led and based on a long-term view and that these rewards should be strengthened. We have previously referred to this as retaining an evolved IQI but are open to an alternative mechanism where this can be demonstrated to deliver for customers. It is key that any business plan incentive mechanism is set out in advance of business plans being developed with customers and stakeholders so all parties can respond appropriately.

CSQ70. Do you have views on the effectiveness of the blended sharing factors approach and in particular the incentive it provides on companies to submit more rigorous totex submissions?

We have responded to questions CSQ70, CSQ71, CSQ72 and CSQ73 together.

CSQ71. Do you agree with our assessment of the blended sharing factor in comparison to the Ofwat cost sharing mechanism? If not, please provide your reasons.

We have responded to questions CSQ70, CSQ71, CSQ72 and CSQ73 together.

CSQ72. Considering the blended sharing factor, what are your views on the factors (eg predictability, ability to effectively deal with uncertainty) or evidence that could be used to distinguish between costs that can be baselined with high confidence and other costs?

We have responded to questions CSQ70, CSQ71, CSQ72 and CSQ73 together.

CSQ73. Do you have any views on the level of cost disaggregation we should apply to calculate the blended sharing factors approach on (regulatory reporting pack level or another level)?

We have responded to questions CSQ70, CSQ71, CSQ72 and CSQ73 together.

Introducing blended sharing factors could give a systematic way to determine how sharing factors will be set in RIIO-2 that links the sharing factor to a more detailed view of the scope for companies to manage these costs. However, as Ofgem identifies, there will be significant complexity and potential implementation challenges associated with this new approach.

At this stage, we do not believe there is sufficient detail to fully understand Ofgem's proposals and increased clarity would be beneficial to allow us to fully assess the intended approach.

In the event Ofgem adopts blended sharing factors, it is essential that these are carefully implemented to ensure that there are no adverse or unintended consequences from the proposed approach.

CSQ74. Do you have any views on whether the proposed business plan incentive coupled with the blended sharing factor will drive the right behaviours?

If correctly calibrated and subject to the comments provided in response to this section and the business plan incentive section, we believe a blended sharing factor may drive the intended behaviours. More work is needed on how these two mechanisms interact because there are clearly potential issues about the relative incentive strengths between the level of reward for an initial lower cost plan compared with a less stretching initial plan and the scope of reward to outperform it in regulatory period at the prevailing sharing factor. However, at this stage, there remain too few details to be able to form a firm view.

CSQ75. What views do you have on our assessment of the sharing factor ranges?

We have responded to questions CSQ75 and CSQ76 together.

CSQ76. Are there any other factors that you think we should take into account in the design of sharing factors?

We have responded to questions CSQ75 and CSQ76 together.

Based on our experience, sharing factors do impact on decision-making and where effort is focussed to identify savings. However, they are not the sole factor that determines companies' approach as factors such as time taken to develop and prove a new way of working along with length of price control will also be relevant. With the shorter five year price control, having strong sharing factors to incentivise companies should be in consumers' long term interests as this will maximise the extent of benefits that companies are incentivised to deliver and consumers will benefit sooner in successive periods.

CSQ77. Do you have any evidence on the scope for productivity improvements in the different sectors?

We suggest that for RIIO-2 and beyond, productivity improvements are just one aspect of what is likely to drive outperformance. Likely to be more important as we support the transition to a low carbon economy is a company's willingness and ability to respond to new challenges and evolve its approach to meet differing customers' wants and needs. We therefore suggest that the scale of the challenge facing a sector should be given at least equal consideration to any scope for productivity improvements and such responsiveness and willingness to change could also be a justification for an increased sharing factor.

In sectors where there are a number of companies and as a result there is competition already between these companies then these sectors will have potentially delivered more productivity improvements as a result of competitive pressure and diversity of approaches followed by best practice sharing.

CSQ78. Do you have views on whether adjustments to sharing factor levels after the price control is set are desirable or necessary?

We have responded to questions CSQ78, CSQ79 and CSQ80 together.

CSQ79. Under which circumstance do you consider such adjustments should take place?

We have responded to questions CSQ78, CSQ79 and CSQ80 together.

CSQ80. When do you consider an adjusted sharing factor should be calculated?

We have responded to questions CSQ78, CSQ79 and CSQ80 together.

In a five year price control, we do not believe it is desirable or necessary to adjust the sharing factor level after the price control is set and believe that the potential for such adjustments is likely to lead to negatively impact on decision making with potential consequential impacts. Changing sharing factors within the five years does not fit well with Ofgem's goal of a simpler regime.

In the event there is a material change to a licensee's allowances, such as the approval of a Strategic Wider Works project, then it may be appropriate to revisit the sharing factor. However, in order to avoid any adverse consequences of such a change, it is essential that Ofgem sets out in which circumstances and how it would treat any case prior to the commencement of the price control period.

10 Fair returns and financeability

CSQ81. Do you agree with our comparative assessment of RAMs set out in Appendix 4?

As previously set out, we appreciate the challenges facing Ofgem in light of calls from some stakeholders with regard to returns in the sector. However, we are unconvinced that the proposed Return Adjustment Mechanisms (RAMs) are necessarily needed to address these, particularly in light of other measures being adopted by Ofgem that will distinguish RIIO-2 from the current price controls. These wider changes that Ofgem is proposing are important to note when attempting to assess the proposed RAMs for RIIO-2 to ensure that the mechanisms developed for this set of controls reflects the issues that may arise from 2021 onwards, rather than seeking to address issues in a preceding control period that can be avoided by developing the existing RIIO approach without adding additional risk, complexity and uncertainty or distorting incentives that essentially work well for consumers in principle.

It is also vital that Ofgem gives due consideration to potential unintended consequences. Proposals that push towards a consolidation of licensees will undermine the credibility of comparative regulation and also reduce benefits for customers. Therefore RAMs need to be based on a licensee basis, rather than Group basis, and Ofgem should ensure that cross subsidisation is eliminated to ensure a fair application across licensees. Ofgem needs to satisfy itself that in developing these proposals they do not narrow the range of viable ownership structures, unless such structures can be demonstrably be shown not to be in customers' interests.

<u>Effectiveness:</u> All of the proposed mechanisms have the potential to adjust returns within the sector. We note Ofgem's statements that the Class 2 options would "*ensure that a sector average cannot exceed or fall below a predetermined level*". However, the examples provided only show situations where a licensee is performing at or above the base cost of equity.

Whilst Class 2 options may allow Ofgem to limit sectoral performance, it does this with potential consequences for the level of performance of individual licence holders. We believe it is more appropriate to focus on licensee levels of returns, rather than company specific, as this aligns with Ofgem's statutory duty to ensure licence holders can finance their activities.

<u>Impact on incentives:</u> We believe all of the proposed options would have a negative impact on incentives as they would, by their very nature, dampen the potential impact of incentives on licence holders' revenue. Of these, Ofgem consider Class 1 sculpted sharing to have the most pronounced effect as companies "*would need to share more of their outperformance*" beyond the threshold. We agree that this could impact on licence holders' decision making. However, unlike the other options, the licence holders are able to understand and forecast the potential impact as part of their decision-making. This will allow informed decisions to be made, for example to curtail investment if returns are likely to reach the threshold.

The Class 2 options may have a different impact on incentives as the sectoral-wide aspects mean that licence holders will only have limited information to make decisions with as they will be unable to factor in the performance of their peers. This inability to forecast potential return on investment could act as a deterrent to investment as shareholders will be unable to be certain what level of return they may achieve. We do not believe this to be in customers' interests as a new and exogenous risk source has been created and is now faced by the company which it cannot manage. Ofgem should clarify how it intends to factor in this increased risk of performance into its assessment of equity risk and beta for RIIO-2.

<u>RAMs will create additional uncertainty for investors in respect of equity returns, further strengthening the case against any expected vs. allowed return adjustment.</u>

<u>Effect on companies' risk profiles:</u> Contrary to Ofgem's assessment, all of these mechanisms have an adverse impact on companies' risk profiles as they all increase the level of uncertainty associated with the returns that might be achievable. Of the proposed options, the Class 1 sculpted sharing has the lowest level of adverse impact as companies are able to forecast when and to what extent it would be applied. The Class 2 mechanisms are significantly more unpredictable as licence holders could not forecast the sectoral average returns and the extent to which the RAM might be triggered. In some cases a company might also be exposed to errors in Ofgem setting the price control for other companies leading to a triggering of the Class 2 mechanism.

<u>Impact on collaboration:</u> We agree that the Class 1 sculpted sharing is neutral in terms of impact on collaboration. We do not believe the alternative approaches are neutral in terms of impact and believe there could be a negative impact on collaboration both within and across sectors from these approaches. We acknowledge Ofgem's observations as to the current levels of collaboration within

and across the sectors but we expect consumer value from collaboration to increase, rather than to decrease, as we move through ED1 and into ED2 with the move to DSO. The assessment therefore understates the potential impact as we transition into a phase of more rapid change and whole system thinking.

Reliance on Ofgem: Any sector based adjustment mechanism relies upon Ofgem setting fair determinations. Returns for other licensees should not be influenced by mistakes in this respect.

Level of complexity & challenges in implementation: We agree that of the proposed approaches, Class 1 sculpted sharing is the most straightforward and transparent approach. It would allow licensees and stakeholders to be able to monitor performance during the period (assuming the proposal to adjust as part of closeout is implemented), avoids the need to take multiple decisions on parameters and is in line with Ofgem's stated desire to simplify mechanisms wherever appropriate. However, any RAMs mechanism should be applied on a licensee by licensee basis to prevent disproportionate impacts on single licensees.

In the event that a RAM other than the Class 1 approach is to be implemented, Ofgem should publish timely annual forecasts of its impact to enable licensees to make appropriate decisions, for example, to defer investment decisions when a negative RAM adjustment is expected to be triggered through over-delivery.

In our response to the Framework consultation, we made a number of suggestions as to the approach Ofgem should adopt if it pursued the use of RAMs. We have refined these thoughts below:

- a licensee specific rather than sector average approach, so the other elements of the RIIO Framework are not diminished;
- it should operate on a licensee by licensee basis. Groups that operate more than one licence are able to transfer performance between licensees, through cost allocations. Ofgem needs to ensure that Groups do not value shift between licensees to evade the potential impact of any RAMs.
- appropriate cap/collar that is at a fail safe level still high enough to incentivise desired outcomes and with a lower level low enough to protect against financeability issues;
- clear criteria that can be applied with a minimum degree of subjectivity, with timely publication by Ofgem of comparative performance, so companies are able to forecast likely outcomes and apply to decision making processes;
- the mechanism should be assessed on a regulatory period basis using the company's performance across the entire period, taking in to consideration the impact of the closeout mechanisms to assess performance against outputs across the period; and
- aspects of a company's performance, including financing and tax should be considered, to understand if the level of return is justifiable based on the service and outcomes being experienced by customers.

We believe these continue to form the suitable basis for evaluating the appropriateness of the design of a RAM and believe that, when assessed against the above, the Class 1 sculpted sharing approach is the least worst RAM Ofgem is considering. This must be supported by a review of the adjustment calculation to ensure that it gives due consideration to the level of justifiable return based on the actual service and outcomes delivered by the licensee.

CSQ82. Do you agree with our proposal not to give further consideration to using discretionary adjustments?

We generally support the removal of discretionary measures as they create uncertainty for investors and company decision-making processes thereby hampering companies delivering benefits to consumers.

However, we note one of the reasons for this is that Ofgem is concerned that it may struggle to distinguish "*between genuine and non-genuine outperformance"*. We recognise this potential challenge but do wonder whether an element of discretion should be built into any proposed RAM to reduce the negative impact of a mechanistic adjustment, factoring in the benefit to consumers of performance. Ofgem is then able to review the calculated adjustment and to then consider, including with consultation, whether or not it is appropriate to apply the calculated adjustment.

CSQ83. Do you agree with our proposal to introduce an individual performance-based adjustment approach (Class 1) for the transmission sectors?

In the event that Ofgem do introduce an adjustment mechanism, based on the information consulted upon, an individual performance-based adjustment approach is the most suitable. Investment decisions are made on an individual company/licensee basis and the RAMs should follow this approach. Comparative mechanisms such as the sector-based approaches fundamentally undermine the ability of management to make informed decisions as they are unable to assess the potential impact of a business case for a discrete project or business change. This creates unnecessary uncertainty, particularly for sectors like electricity distribution where significant investment is likely to be required during the ED2 period to ensure we can successfully support our customers and stakeholders through the low carbon transition.

In the specific case of the transmission sectors, we question how the dominance of one licensee in each of ET and GT can be managed to ensure fair adjustments and look forward to seeing Ofgem's proposals in this regard.

It should be noted that even an individual performance adjustment has the potential to disincentivise optimal performance, as the opportunity to drive performance is effectively constrained for well performing companies. Ofgem needs to consider whether this is likely to result in the desired management focus for the RIIO-2 period, the objective of greater simplicity and to maximising benefits to consumers.

CSQ84. Do you agree with our proposal to introduce a sector average-based adjustment approach (Class 2) for the GD sector?

In the event that Ofgem do introduce an adjustment mechanism, we do believe that an individual performance-based adjustment approach to be the most suitable so we do not agree with a sector average based approach. Investment decisions are made on an individual company/licensee basis. Comparative mechanisms such as the sector-based approaches fundamentally undermine the ability of management to make informed decisions as they are unable to assess the potential impact of a business case for a discrete project or business change. This creates unnecessary uncertainty, particularly for sectors like electricity distribution where significant investment is likely to be required during the ED2 period to ensure we can successfully support our customers and stakeholders through the low carbon transition.

Network companies should not be able to hold each other 'hostage'. Proposals for cross-sector averages put licensees at the mercy of other players, without the information to be able to make informed decisions. A GDN cannot know how ambitious (or not) other plans are, yet the current proposals tie their ultimate returns to how ambitious or not the plans of others are and then how other management teams deliver against them. We do not believe this to be in customers' best interests, nor to be a simplification of the regime.

Again, we iterate that the adjustment should not unfairly increase the predictability of returns for a single licensee compared to multiple licensee groups.

CSQ85. Do you agree with our proposal we should not adjust companies downward if they perform below their base cost of equity or upwards if they perform above their base cost of equity?

For the reasons set out in response to question CSQ84, we do not believe the Class 2 approach is appropriate. However, of the proposed alternatives set out in paragraph 10.79, we do believe this is the least worst approach for consumers. We think this mitigates some of the potential external risk to companies that the Class 2 approaches introduce.

CSQ86. Would a return adjustment threshold of ±300bps RoRE achieve a good balance between providing scope for companies to outperform and ensuring return levels are fair?

The consultation document provides no explanation to support the proposed adjustment threshold of ±300bps RoRE. This makes it difficult to be able to have a view as to whether or not this is an appropriate band for the adjustments to operate around.

As the current consultation is not considering electricity distribution, we cannot consider the proposed range against the backdrop of proposed incentive mechanisms. Calibration against these needs to take place in order to be able to form an opinion on the appropriate range for electricity distribution.

In particular, it is not feasible to asses 300bps without knowledge of the investment and its risk required to achieve incentive income, at any given particular level.

We generally support the use of symmetrical mechanisms. However, consideration does need to be given as to how the potential downside of RAMs interacts with Ofgem's financeability duty and cash flow floor proposal, especially if a sector average approach is adopted. It does not seem appropriate that the actions of other players could result in a company triggering the cash flow floor nor how these mechanisms would interact as the RAM is likely to be triggered at the end of the period whilst the cash flow floor is within period. It is difficult to understand how sign offs on availability of resources, as mooted under cash flow floor proposals can be made, absent a full picture of RAMs impacts.

CSQ87. What are your views on the proposed use of RoRE as a return adjustment metric? Would it be suitable for the gas and electricity transmission sectors and the gas distribution sector?

As previously set out, RoRE may be a suitable metric if it is correctly calculated and includes all factors that affect returns for the specific company, including financing and tax. We are pleased that Ofgem is now publishing this full picture of returns.

We consider it appropriate that RoRE based on actual gearing is used, rather than RoRE based notional gearing, as this more closely reflects actual returns earned by equity holders.

We note that RoRE on an actual basis could be impacted by strategically adopting a gearing structure materially below notional level, thereby triggering RAMs. To the extent that deviations from notional gearing levels reflect financing strategy, rather than prudent risk management, Ofgem should consider restricting the differential between RoRE on a notional basis and RoRE on an actual basis to prevent gaming and thereby protecting consumers.

It is also essential that closeout mechanisms are developed prior to the commencement of controls to allow for an accurate calculation of RoRE so returns are stated after enduring value adjustments recognising future adjustments that may be applicable, especially through uncertainty mechanisms and the Totex Incentive Mechanism.

As a DNO, our consideration of whether or not RoRE may be suitable as a metric under RAM's is based on our experience in electricity distribution.

Any returns adjustment mechanism should be applied fairly across licensees. Groups that operate more than one licence are able to transfer performance between licensees, for example through central cost allocation. To be fair, any mechanism would have to operate on a licensee by licensee basis, and Ofgem would need to assure that other licensees performance within Groups has been fairly presented, otherwise its application would disproportionally impact on smaller licensees.

CSQ88. Should we include financial performance within the scope of return adjustments? If not, what is the rationale for excluding financial performance?

Firstly, we reiterate our concerns with Ofgem's proposal for full indexation of the debt allowance, calibrated based on sector average performance. We believe this methodology unfairly benefits large companies that can raise funds each year at above benchmark issuance size; and companies that are fortunate in the timing of issuance. We also highlight that out/under performance on financing would be largely set at the time of calibration, leaving companies with little opportunity to rectify.

We strongly believe that the debt allowance should be based on individual licensee's (not Groups') debt positions in accordance with Ofgem's financeability duty.

Notwithstanding these concerns, we believe that it is appropriate for return adjustments to be based on a post financing and tax RoRE. To exclude financing and tax performance from this or other mechanisms to consider returns within the sector is misleading and does not provide an accurate view of under- or over-performance within the sectors.

CSQ89. Should we implement adjustments through a 'true-up' as part of the annual iteration process or at the end of the price control as part of the close-out process?

We believe that adjustments should be made as part of the closeout process, subject to the mechanism for closing out the price control being clearly established prior to the commencement of the price control. Whilst this does not remove the requirement to ensure closeout mechanisms are properly developed prior to the commencement of price control periods, it does allow all relevant parties to understand the impact of these mechanisms and to ensure that there are no unintended consequences from its application. However the evolving potential impact on licensees through the price control period should be provided by Ofgem annually, in order to ensure predictability of returns.

A single adjustment should also minimise charging volatility and assist other parties to be able to accurately forecast their costs.

11 Achieving a reasonable balance in RIIO-2

CSQ90. Do you agree with our assessment of the measures we have identified to make the price control more accurate?

We have answered questions CSQ90, 91 and 92 together.

CSQ91. Are there other measures we should take to improve the accuracy of the price control?

We have answered questions CSQ90, 91 and 92 together.

CSQ92. Are there other steps we could take to simplify the price controls, without significantly affecting the accuracy of the control?

We have answered questions CSQ90, 91 and 92 together.

We are unclear what Ofgem means when it refers to '*the accuracy of the price control*'. Assuming this relates to a very close match between allowances and expenditure then the very nature of price controls means it is almost impossible to establish an 'accurate' control as there will always be deviations from the plan as these are based on forecasts, unless significant ex post adjustments are introduced. We do not believe such adjustments would be in line with the RIIO framework or with incentive-based regulation more generally.

We therefore advocate that Ofgem should be seeking a control that is 'appropriate', that recognises that there will be aspects that deviate from plan (and the use of uncertainty mechanisms is a sensible response to this) and that incentive regulation is complex but can be made more accessible through transparency and engagement.

Given the reduction in returns, risk reductions should be made, including concluding on all licence conditions (including the detail of close out mechanisms) prior to the commencement of the price control period.

Several of the potential new mechanisms, for example RAMs and the Cash Flow Floor are not necessary in any event, but also run counter to the intent of simplifying the price control, especially when the effect of these novel mechanisms are compounded together.

CSQ93. Do you agree with our consideration of the risks facing these companies? Do you think the measures we are proposing will mitigate these risks? Does the expected level of return indicated by our proposals reflect these risks?

Ofgem has stated it wanted to develop a lower risk, lower return package for network companies in RIIO-2. Our observation on the developments for RIIO-2 to date is that risk (such as complexity and uncertainty due to the framework) is actually increasing whilst returns are proposed to be substantially reduced.

Ofgem's consideration of the types of risk facing network companies assumes that the risks facing networks companies are uniform irrespective of the sector. We do not believe this is correct. Electricity distribution faces a systematic risk that it is often the primary facilitator for Government policy to deliver the transition to a low carbon economy. As a consequence, we have seen significant change through ED1, with the DNOs being asked to take on additional roles and responsibilities within the pre-determined allowances. Whilst we believe that some of the potential scope creep can be addressed for ED2 through appropriately set uncertainty mechanisms, this does not fully mitigate the risk to DNOs. In the event that Ofgem decides to lower the allowed cost of capital for electricity distribution, there will be less headroom for DNOs to absorb such additional scope. We do not believe that risks such as this have been appropriately factored into Ofgem's consideration of the appropriate level of return.

CSQ94. Have we achieved a reasonable balance with our proposals in seeking to achieve an accurate price control with return adjustment mechanisms only being used as a failsafe? Should we instead have a simpler price control and put more reliance on return adjustment mechanisms?

We do not agree return adjustment mechanisms are appropriate as these increase framework complexity and uncertainty and are new sources of risk. Ofgem should focus on and have confidence in learning from price control setting experience and set appropriate allowances and incentives in the first place. In our response to the Framework consultation, we set out our concerns that proposals for the development of return adjustment mechanisms were being driven by concerns with the calibration and implementation of the RIIO Framework, rather than from the structure of the regime itself. We continue to believe this remains the root cause of the concerns Ofgem has sought to mitigate through the development of RAMs. As described in response to question CSQ100-102, we believe Ofgem should be seeking a control that is 'appropriate', that recognises that there will aspects that deviate from plan and that incentive regulation is complex but can be made more accessible through transparency and engagement.

As the proposals currently being consulted upon are not directly applicable to electricity distribution, we are unable to assess whether they are accurate or appropriate. However, it is our view that RAMs should not be needed where an appropriate control is set and are too broad a brush to ever be used as anything beyond a fail-safe mechanism which really should not be required in the first place as instigating RAMs may distort risk profiles and incentives from those that best serve consumers.

CSQ95. Have we achieved a reasonable balance in our proposals in considering return adjustment mechanisms alongside the expected-allowed return wedge? Should we instead only rely on one mechanism? What additional value would this bring?

We do not believe that there is a balance between the proposed RAMs and the proposed expected-allowed return wedge. The proposed expected-allowed return wedge has not been adequately justified and comes with a number of fundamental issues that mean it should not be taken forward as a negative adjustment. The purpose of both of these mechanisms is to drive down the achievable return, although they seek to achieve this objective through different means. There is a risk that the use of both mechanisms undermines broader investor confidence within the energy networks, resulting in investors seeking alternative investment options. At a time when significant investment is likely to be required in GB networks, and particularly electricity distribution to facilitate the low carbon transition, deterring investment is unlikely to be desirable and may have unintended adverse consequences.

CSQ96. Have we got the right focus on the areas that are of most value to consumers?

Our stakeholders have told us that they believe the areas of highest priority for Electricity North West at present are: transitioning to the low carbon economy; keeping their lives running; delivering energy efficiency; providing support for vulnerable customers; addressing fuel poverty; improving network resilience; and investing in the North West. We will continue to test and confirm this with our customers and stakeholders as we progress the development of our Business Plan for ED2.

As the current consultation focuses on the other sectors, we cannot confirm whether or not Ofgem has achieved the right focus to enable us to deliver the areas of most value to our customers in ED2. However, we expect to work with Ofgem as it develops its thinking for ED2 and will seek to represent the needs and wants of our customers through this process.

As Ofgem continues to refine its thinking, we believe it is important that the current pressure on Ofgem to reduce returns as a consequence of distortions in the RIIO-1 controls, particularly for transmission and gas distribution, do not create a barrier to investment in ED2 as this would be detrimental to our customers.

CSQ97. Are we proposing a methodology that allows us to achieve a reasonable balance between the interests of different consumer groups, including between the generality of consumer and those groups that are poorly served/most vulnerable? Are we missing any group?

Based upon our stakeholder research, we believe it may be "*appropriate to fund targeted company action to support consumers in vulnerable situations*." As an industry going through significant change, it is important that we are mindful of those customers who may struggle to participate in this change, whatever the vulnerability, and it seems appropriate that licence holders are able to ensure customers less able to engage are supported to an appropriate extent through this transition to minimise the risk of different groups of customers being disproportionately disadvantaged or even left behind.

However, both the assumption that this is supported by customers and the extent to which it is supported require further testing. Ofgem's approach also assumes that there is a general acceptance that energy costs, rather than taxation or other measures, are the most appropriate means to fund this redistribution of wealth which would also benefit from validation.

CSQ98. Are we proposing a methodology that allows us to achieve a reasonable balance between the interests of existing and future consumers?

We recognise that Ofgem is seeking to balance the interests of existing and future consumers. However, as the majority of proposals within the consultation documents lack qualitative assessment, such as cost benefit analysis or discounted net present value analysis, it is difficult to understand how this balance has been struck. We are aware that Ofgem does face significant pressure to reduce costs to existing consumers. Measures such as reducing the allowed returns and down aiming an allowed vs expected wedge do appear to be focussed on addressing these near-term concerns but could have significant long-term and detrimental impacts on future consumers. Undertaking a full impact assessment on the costs and benefits of proposals, both separately and combined as a package, would demonstrate the balance Ofgem has sought to achieve through this process and also ensure that future decision-making can be informed by any changes to the underlying assumptions.

12 Preliminary impact assessment questions

CSQ99. What are your views on the approach we are proposing for assessing impact of our RIIO-2 proposals?

We have answered questions CSQ99, 100, 101 and 102 together.

CSQ100. What are your views on the assumptions we have made in our assessment to date?

We have answered questions CSQ99, 100, 101 and 102 together.

CSQ101. What are your views on the uncertainties we have identified for the purpose of this assessment?

We have answered questions CSQ99, 100, 101 and 102 together.

CSQ102. What additional evidence should we consider as part of our ongoing assessment?

We have answered questions CSQ99, 100, 101 and 102 together.

We do not believe the approach to assessing the impact of Ofgem's RIIO-2 proposals is appropriate. The approach also does not appear to be in line with Ofgem's guidance on how to undertake Impact Assessments[1], particularly the expectations for how an Impact Assessment will be undertaken in accordance with s5A of the Utilities Act.

We recognise that Ofgem has sought to assess the costs and benefits of its proposals in terms of Consumer Bill Impact, Enabling the energy system transition, Impact on quality of service and Other Impacts. We also acknowledge Ofgem's statement that some of the proposals "*can only be assessed qualitatively*". However, there is a lack of substantive, quantitative analysis to underpin the Impact

[1] Ofgem, 'Impact Assessment Guidance', October 2016, https://www.ofgem.gov.uk/system/files/docs/2016/10/impact_assessment_guidance_0.pdf

Assessment and the Appendix does not seem to be objectively set out considering a full range of factors, so a much more robust assessment is required for proposals of this significance.

Ofgem's Guidance recognises that Impact Assessments will need to evolve as policy develops and we would expect the level of detail to increase as Ofgem works through the price control process. However, as decisions will be made on key aspects of the methodologies for transmission and gas distribution, and potentially on proposals that may be capable in principle of application to electricity distribution, we do not believe it is acceptable for Ofgem to base its decisions on the potential cumulative impact of its proposals on the limited information provided in Appendix 5.

We expect Ofgem, in accordance with its Guidance, to outline the Option appraisal process it has undertaken, considering monetised CBA, distributional effects and hard to monetise impacts, for its new proposals, particularly where those proposals substantially depart from the approach adopted for RIIO-1, including slow-track ED1 proposals, or introduce a new approach. These impacts should be assessed both on an individual policy basis and a cumulative basis, and should consider the impacts on actual, as well as notional, companies particularly where Ofgem is aware of material differences between companies.

Appendix 2: response to Finance questions

March 2019

Contents

1 Overview

Electricity North West Limited (ENWL) is an electricity Distribution Network Operator (DNO). We recognise that Ofgem is "*not consulting on proposals for the next electricity distribution price control at this stage*" (paragraph 2.30), however, we are mindful that Ofgem has also indicated that measures with the current consultation "*may be capable, in principle, of application for ED2*" (paragraph 2.31).

Whilst we support many of the proposals in the Cross-Sector Methodology as described in Appendix 1 of our response, we remain extremely concerned that there are a number of areas in the Finance Annex where Ofgem's proposals are inappropriate or suffer from a lack of detail. We address these issues in detail within this Appendix.

Our interest stems from our understanding that the same broad design principles that inform the methodology for these sectors could apply to ED2 and that the starting point for considerations of ED2 could be the decisions made for these sectors.

This Appendix should be read in conjunction with the RIIO-2 sector specific cover letter, response to the cross sector document and in light of previous correspondence in relation to RIIO-2.

The independent consultant reports referenced within our response are being provided alongside the Energy Networks Association's (ENA) response to this consultation and are therefore not appended to our individual response.

2 Cost of debt questions

FQ1. Do you support our proposal to retain full indexation as the methodology for setting cost of debt allowances?

We do not support the proposal to retain full indexation as the methodology for setting cost of debt allowances.

The methodology is unsophisticated and does not respond well to sharp changes in capital markets rates. Complexity should not be a barrier to ensuring a fair and reasonable regulatory framework.

Any calibration based on sector average is likely to result in a wide dispersion of performance across licensees. Careful review would then need to be carried out to increase the allowance for efficient, but underperforming companies in accordance with Ofgem's duty to ensure each licensee is financeable. Overall, customers would therefore pay more than is necessary.

A sector average approach, absent specific adjustments, will establish winners and losers at the outset of the determination, leaving companies with no real options to change the outcome over the regulatory period. These winners or losers may be the result of size or merely the luck of timing of refinancing, rather than any actual inefficiency of financing arrangements.

Small companies have a structural disadvantage to meeting any trombone or roller mechanism, with 1/10th to 1/20th of debt being well below benchmark size. Small companies face the choice of incurring additional transaction costs and issuance premiums on frequent issuances, or the additional costs of carry associated with grouping financing needs into above benchmark size. This latter option also increases the exposure of small companies to fortunes of timing.

Any assessment of company debt costs needs to incorporate all financing costs which include appropriate estimates of transaction, liquidity and carry costs for each company. It is likely that these costs are higher overall for small companies or more frequent issuances (if companies choose to try to reduce risk by matching the index).

Financing costs should also explicitly include the cost or benefit of derivatives. Derivatives are entered into primarily for risk management purposes and it is unreasonable to view their impact in isolation. It is unfair on consumers to treat outperformance on direct borrowing, which is effectively shared through calibration each regulatory cycle, any different to that gained through derivatives, which would be excluded from calibration if they were ignored during assessment. Derivatives used to correct nominal to RPI debt, together with its underlying nominal debt should be treated consistently with index linked debt.

We do not believe any adjustment for Halo costs is necessary. The analysis provided by Nera in its 'Cost of Debt at RIIO-2' report (*March 2019*) would support this view. Should Ofgem decide to undertake further analysis, it is important that any assessment of the Halo effect should make all necessary adjustments for credit rating of issuer, tenor and concavity of bonds.

FQ2. Do you agree with our proposal to not share debt out-or-under performance within each year?

We consider it appropriate that debt under/out performance is shared each year, in line with other aspects of regulatory performance, on a cumulative basis.

Debt under/out performance should be treated in a similar way to Totex and Ofgem should provide evidence and support as to why it should be treated any differently to other areas of under/out performance within the price control.

If companies successfully outperform the debt allowance, for instance through securing private placement financing below iBoXX rates, it is fair that customers should benefit during the regulatory period.

A framework that does not adequately remunerate networks may lead to short-termism, negatively impacting customers.

FQ3. Do you have any views on the next steps outlined in Finance annex paragraphs 2.22 to 2.25 for assessing the appropriateness of expected cost of debt allowances for full indexation?

The setting of the cost of debt allowances needs to be based on Ofgem's financeability duty to ensure that each licensee is financeable, based on its particular circumstances subject to an efficiency test. Averaging across sectors is too wide a starting point, particularly now that Ofgem has full details of each company's specific circumstances through the RFPR data collection.

We do not support the proposal to retain full indexation as the methodology for setting cost of debt allowance, or that calibration of the allowance should be based on sector averages. Sector averages will give rise to winners or losers, which may then require adjustment to losses as a result of Ofgem's financeability duty. Overall this approach would result in customers paying more than would be justified on a licensee by licensee approach.

Table 1 below illustrates the issue. The data is extracted from Ofgem's Regulatory Financial Performance annex to RIIO-1 annual reports 2017-18 and shows the ED1 sector having a debt allowance matching its costs, but with significant winners and losers.

Table 1 – Annual Performance

Annual financing performance		ENWL	NPg	SP	SSE	UKPN	WPD	ED1
Financing performance (notional)	£m 12/13	(16.1)	(1.4)	19.1	5.8	13.0	(17.3)	**3.0**
Financing performance (actual)	£m 12/13	(12.9)	6.6	19.7	5.4	12.5	(14.7)	**16.6**
Equity (notional)	£m 12/13	545.1	960.5	1,123.8	1,051.3	1,815.6	2,260.4	**7,756.8**
Equity (actual)	£m 12/13	642.2	1,432.4	1,201.5	1,052.5	1,774.5	2,415.6	**8,518.7**
RoRE % (notional)	%	(3.0)%	(0.2)%	1.7 %	0.6 %	0.7 %	(0.8)%	**0.0 %**
RoRE % (actual)	%	(2.0)%	0.5 %	1.6 %	0.5 %	0.7 %	(0.6)%	**0.2 %**

Source: Ofgem Annual Report 2017-18

While overall sector performance for ED1 is 0.0% (notional) there is wide dispersion of network performance.

There are limited practical opportunities for companies to 'match' existing debt portfolios to any roller or trombone mechanism, particularly for smaller companies, and we believe that there will continue to be a wide level of dispersion of financing performance in RIIO-2 under full indexation.

With Ofgem guiding towards a 50% reduction in equity returns, we believe that a full indexation approach could lead to financeability issues for companies in RIIO-2.

When assessing the appropriateness of any debt allowances, it is critical that Ofgem include all relevant costs in any estimates for future financing, including:

(1) Derivatives. These are primarily risk management tools to protect against inflation risk.
(2) Direct and indirect issuance costs, including legal, advisory and rating agency fees.
(3) Liquidity costs, including carry costs on operational cash.
(4) Appropriate refinancing assumptions, including periods of pre-financing and/or commitment fees.
(5) Financing rates based on current credit ratings, not simple sector average. The Halo effect should be evaluated and incorporated if appropriate. As we explain in our response to FQ1 we do not currently believe an adjustment for Halo costs is justified.
(6) Any appropriate non-issuance costs, including adjustments for premiums or discounts on issuance or redemption. For the avoidance of doubt, we do not believe it is appropriate to adjust interest costs to reflect current Yield To Maturity on public debt, only the actual cash impact on issuance or redemption.

Ofgem states that it will consider whether a smaller company allowance is appropriate, and we would therefore raise the following points for consideration by Ofgem:

- **Legitimacy.** It is not in the interests of customers to set a debt allowance in line with weighted-average debt costs for the sector as a whole, and then to offer small companies extra allowances. Absent adjustments for "larger companies", customers would then end up paying more than they would do if allowances were set fairly on a licensee (or group) by licensee basis.
- **Additional financing costs for smaller companies.** Small companies may face additional costs across all six areas noted above and any assessment must extend outside of simple differences in coupon and relative transaction costs. Larger groups often have central Treasury functions that benefit from the portfolio effect of several companies, accessing markets frequently and aligning debt profiles with any roller/trombone mechanism.

Regarding assessment of company financing costs, providing that RFPR data incorporates all costs noted 1-6 above and that methodology is aligned between companies (but still allowing for company-specific variations), then we would support RFPR data being used to assess costs.

We strongly disagree with Ofgem's proposal for sector average calibration however, should it be implemented, we believe it should be in the context of the following objectives:

- Limit the dispersion in performance between licensees
- Limit the performance impact arising on sharp changes in financing rates (gilts, credit spreads, inflation)

Ofgem should tailor its methodology to achieve this, including the introduction of company specific adjustments where appropriate, such as adjustments for both smaller and for larger companies, or indexation weighted according to issuance.

Ofgem should state how it will apply a sector specific average approach when certain larger groups dominate a sector (such as transmission), and how, in that case, the policy does not mathematically result in quasi company specific allowances for the largest group.

We do not believe that simplicity should take precedence over these objectives and it is far more important that financeability and fairness are achieved.

As an alternative to the methodology proposed by Ofgem we would support an indexation methodology that reflected an individual company's profile of issuance. This would eliminate the windfall gains and losses derived from fortunes of timing and remove the motivation for companies to conform financing structures to unrealistic roller or trombone mechanisms. In addition, by retaining external benchmarks for financing costs, it would continue to incentivise companies to outperform without being unduly complex.

An appropriate debt allowance is a cornerstone of individual company financeability, therefore it is imperative that Ofgem give the methodology and calibration due consideration, including the impact of derivatives.

It is essential that Ofgem undertake a full, stress tested impact assessment on how the debt allowance will impact individual company financeability. The RIIO-ED1 debt performance figures provide a basis for this. An impact assessment for all licensees should be carried out before RIIO-2 methodologies are finalised in order to ensure that the methodology results in conformity with Ofgem's financeability duty.

FQ4. Do you have a preference, or any relevant evidence, regarding the options for deflating the nominal iBoxx as discussed in Finance annex paragraph 2.14? Are there other options that you think we should consider?

There should be consistency between the RAV indexation and the deflation of the nominal-WACC. Breakeven inflation, measured as the difference between nominal and RPI-linked Gilts, is not an accurate method of predicting RPI inflation across a regulatory period. RPI estimates using this method are impacted by market distortion, particularly given that demand for RPI linked debt is outstripping supply.

Long term breakeven inflation does not accurately reflect the inflation expectations across a five year regulatory period.

Providing there is no conflict with the overriding principles noted above, we would support using OBR or HMT CPI(H) inflation forecasts for deflating nominal iBoxx indices.

3 Cost of equity

3.1 Risk-free rate

FQ5. Do you agree with our proposal to index the cost of equity to the risk-free rate only (the first option presented in the March consultation)?

We believe it is largely unnecessary to index the risk-free rate component of the CAPM model given other proposed regulatory framework changes. The existing RIIO toolkit, if applied appropriately, contains all the controls necessary to maintain an appropriate return to shareholders. Furthermore, shortening the price control period from eight to five years will limit opportunities for unchecked material movement in the risk-free rate.

Equity investors deliver patient capital for the long-term, basing their investment decisions on long-term averages. Regulatory stability and decision-making are crucial components in attracting such capital.

While we consider indexation unnecessary, rating agencies have suggested that equity indexation may be marginally credit positive, because it constrains a regulator from setting an inappropriate equity allowance. Given the material financeability pressures inherent in the RIIO-2 package as proposed we feel it necessary to support indexation for this reason.

If Ofgem is to use trailing indexation, it should ensure that the underlying data sets are robustly accurate and not subject to presumptions to make up for gaps in data or research. To maintain legitimacy and fairness, the introduction of such a mechanism will require a long term commitment from Ofgem, well beyond RIIO-2 price controls to apply the mechanism throughout all market conditions in the future.

Care needs to be taken to ensure that returns remain sufficient to attract the capital needs of an asset intensive business, particularly during periods of market distress or significant market change. NERA's paper for the ENA, "Cost of Equity Indexation Using RFR" (*March 2019*), recommends using 20 year nominal gilts based on 12 month averaging prior to the charging year. We support NERA's position and recommendations on using nominal gilts.

Finally, we note the current RIIO-1 framework disjoint between (i) long-term inflation expectations being used to deflate the nominal WACC and (ii) RAV and revenue growth being inflated based on actual outturn inflation. This disjoint results in cash flow risk for networks, particularly in periods where short term inflation expectations deviate from long run average. Ofgem should seek to address this disjoint for RIIO-2.

The current use of RPI breakeven as a proxy for long term inflation expectations is flawed due to supply-demand imbalance for RPI linked debt. The supply-demand balance for long-dated index-linked government debt is currently unequal. Demand far outstrips supply, increasing prices and suppressing inflation linked yields. Pension funds and life companies have unfulfilled demand for index-linked income and, most importantly, for the inherent liquidity risk protection that is actively encouraged by the Government and Pension Regulator. This has implications for the use of gilt spreads when estimating market expectations of inflation.

FQ6. Do you agree with using the 20-year real zero coupon gilt rate (Bank of England database series IUDLRZC) for the risk-free rate?

As noted in the response to FQ5, we believe that real gilt yields are frequently distorted due to a supply-demand imbalance for RPI-linked debt. Pension funds and life companies have unfulfilled demand for index-linked income and, most importantly, for the inherent liquidity risk protection that is actively encouraged by the Government and Pension Regulator.

In normal market conditions, the use of long-term nominal gilt yields is considered an appropriate proxy for the nominal risk free rate. While so, we do not believe rational investors without any specific hedging requirements would accept a negative real return on risk free investments.

A negative real Risk Free Rate (RFR) is both unsustainable and counter-intuitive to the investment strategy of pension funds, which are looking to invest to receive RPI+ returns. We note that there are significant pension fund liabilities that have RPI inflation written into their trust deeds, hence them seeking returns above RPI and not merely above inflation. It would imply that such funds are investing to lose money, long-term, on a real basis. Ofgem should be mindful that the cost of equity determination needs to be defensible to the life and pension funds that are significant long term investors into UK infrastructure. As such we consider it appropriate that any approximation to the Risk Free Rate should be subject to a floor.

As noted in FQ5, NERA's recommendation in its paper "Cost of Equity Indexation Using RFR" (*March 2019*) is to use nominal rather than real gilt yields. The evidence they present in the Appendix from Schroders supports this position.

Regarding any inflation adjustment to calculate a real risk free rate, we again highlight the current framework disjoint between the long-term inflation expectations being used to deflate the nominal WACC; and RAV and revenue growth being inflated based on actual outturn inflation. Ofgem should seek to address this disjoint for RIIO-2.

FQ7. Do you agree with using the October month average of the Bank of England database series IUDLRZC to set the risk-free rate ahead of each financial year?

Point in time estimates are subject to a greater risk of distortion. Also noting concerns with the indexation approach (FQ5), and using the series in isolation (FQ6), we would favour some period of averaging when setting the Risk Free Rate.

We support NERA's proposal ("Cost of Equity Indexation Using RFR", *March 2019*) to base any calculation on a twelve month average prior to the charging year. NERA's work indicates that twelve months provides for more stable estimates and is likely to be more reflective of the interest rate variations over the year.

FQ8. Do you agree with our proposal to derive CPIH real from RPI-linked gilts by adding an expected RPI-CPIH wedge?

We do not agree with Ofgem's proposal to derive CPIH real from RPI-linked gilts by adding an expected RPI-CPIH wedge. This principally reflects the concerns noted in FQ4-7 regarding the potential distortion in RPI-linked gilt yields.

Subject to an appropriate floor in the measure of Risk Free Rate, it is considered more appropriate to derive an appropriate CPIH real from the nominal rate, using an estimate of inflation that is aligned to the inflation expectations over the regulatory period.

Again, we support NERA's ("Cost of Equity Indexation Using RFR", *March 2019*) recommendation to use nominal gilts and deflate using an appropriate CPI forecast derived from HMT or OBR forecasts.

3.2 TMR

FQ9. Do you have any views on our assessment of the issues stakeholders raised with us regarding outturn inflation, expected inflation, and the calculation of arithmetic uplift (from geometric returns)?

We agree with the broad stakeholder issues summarised by Ofgem in the consultation document, but do not agree that the information adequately represents the underlying arguments and considerable weight of the evidence as provided by both academics and consultants on this issue.

We share NERA's concerns about some of the UKRN conclusions and Ofgem's interpretation of the UKRN study, particularly its interpretation of historical data. We support NERA's conclusions ("Review of UKRN Report Recommendations on TMR", *December 2018*), highlighting the flawed nature of the UKRN report on this matter; and therefore the TMR ranges in the Ofgem consultation document on which this judgement relies:

1) "NERA's analysis shows that the Millennium CPI dataset does not provide a reliable measure of historical CPI inflation. This has been clearly acknowledged by the ONS and academic research. We conclude that the historical TMR back to 1900 must instead be calculated relative to the "official" RPI inflation." ("Review of UKRN Report Recommendations on TMR", p4).

2) "The UKRN's assertions on the issue of the "predictability" of returns do not appear to be well founded. NERA conclude that the CMA's (NIE, 2014) position on this issue is much more robust." ("Review of UKRN Report Recommendations on TMR", p4).

3) "A Real TMR deflated by RPI cannot be used in a CPI framework without adjustment" ("Review of UKRN Report Recommendations on TMR", p5).

It is our belief that, to the extent that matters are subjective Ofgem should also consider the alternative views advanced by NERA and others to gain a consensus in approach. In order to maintain a balanced and fair approach to the underlying arguments, we believe Ofgem should instruct a third party academic review to independently assess the UKRN approach and stakeholder issues.

We are aligned with Oxera's position ("The cost of equity for RIIO-2", *February 2018*) on arithmetic vs. geometric averaging and consider that arithmetic means are more appropriate than geometric means as an averaging method in this context. Use of arithmetic means is more broadly supported by regulatory precedent and academic research in estimating equity market returns. Any departure from existing regulatory precedent would need compelling justification.

FQ10. Do you have any views on our interpretation of the UKRN Study regarding the TMR of 6-7% in CPI terms and our 6.25% to 6.75% CPIH real working assumption range based on the range of evidence?

We believe it is important for Ofgem to consider the full weight of evidence in respect of the TMR, to enable a fair, reasonable and objective conclusion to be drawn. Singular reliance on the UKRN report conclusions that have been shown to be subjective, does not in our opinion, demonstrate a reasonable regulatory assessment.

We refer to the response to FQ9 above, and in particular the first point extracted from the NERA ("Review of UKRN Report Recommendations on TMR", *December 2018*). In our opinion this confirms the subjective nature of interpreting historic data measurement, and the range of TMR conclusions this can deliver.

NERA conclude that the data labelled as CPI inflation taken from the Millennium dataset for years prior to 1987, does not represent a reliable measure of CPI inflation. This is supported by similar conclusions by the ONS. Furthermore, the Millennium dataset, utilised by the UKRN TMR analysis for the period 1915 -1949, equates a CPI index with a RPI index. This cannot be correct, and should not be overlooked by Ofgem, particularly when relying on such evidence to justify the TMR ranges in their RIIO-2 proposal.

FQ11. Do you have any views on our reconciliation of the UKRN Study to previous advice received on TMR as outlined at Finance annex appendix 2?

Our key concern with Ofgem's approach to the reconciliation is that it omits a significant step relating to the change in inflation basis in arriving at a "real" number. The 2003 and 2006 studies were presented and interpreted as being on a real-RPI basis. The 2018 report is on a CPI basis.

We believe any reconciliation such as that presented in Figure 8, needs to expressly reconcile the 2006 TMR figure (RPI) to 2018 report (CPI), by first reconciling to the 2006 TMR figure in CPI.

Apart from this important point we have no further comment on the reconciliation as presented except that we have fundamental concerns about UKRN's construction of the endpoint.

Our understanding is that the construction of the reconciliation is Ofgem's work and would suggest that Ofgem ask UKRN to verify this approach, or present an alternative in order that all UK regulators are aligned?

3.3 Equity beta

FQ12. Do you have any views on our assessment of the issues that stakeholders raised regarding beta estimation, including the consideration of: all UK outturn data, different data frequencies, long-run sample periods, advanced econometric techniques, de-gearing and re-gearing, and the focus on UK companies?

Ofgem has taken a fundamentally different approach to beta estimation than used in previous determinations, namely placing significant weight on the use of GARCH modelling techniques, thereby breaking with established regulatory and CMA precedent. We do not believe that this is appropriate given the degree of subjectivity involved in the assessment and difficulties with modelling assumptions and specification. We believe that with the lack of compelling evidence of a consistently superior modelling approach (see responses to FQ13 and FQ14 below), any starting point for beta analysis should be established regulatory precedent (i.e. the use of OLS and daily data over a time period no greater than five years) to avoid the problem of including data points that may not be representative of the current systematic risk of the business.

Our view is consistent with approaches and arguments outlined in Oxera's February 2018 ("The cost of equity for RIIO-2") and May 2018 ("Review of Ofgem's initial cost of equity proposals for RIIO-2") reports.

For the reasons outlined by Oxera, GARCH techniques employing long term data at a reduced frequency level have their own drawbacks. Utilising such datasets introduces complications regarding structural breaks, use of data from very unusual economic circumstances and the disregard of data points by moving away from the use of daily data. Issues arise from specifying the correct model. None of this leads to superior, clear, consistent and reasonable answers - quite the contrary, it complicates the picture.

We believe it is unreasonable to place significant weighting to the GARCH techniques without firm justification. A forthcoming Oxera report for the ENA examines in further detail why use of GARCH over OLS is problematic.

We also have concerns about Ofgem's 'adjusted' gearing ratio approach and believe each company should be separately de-geared using its own gearing ratio rather than apply a blanket and subjective EV/RAV (1.1x) approach. We believe this is necessary to control for individual company circumstances such as their capital structure and financial risk. Applying the proposed 'adjusted' gearing approach potentially ignores the spread of raw equity betas and gearing across UK utilities. It is also a departure from established practice without adequate justification.

With regard to the use of UK data, we remain supportive of Oxera's stance in their report ("The cost of equity for RIIO-2", February 2018) that, given the small sample set of relevant comparator companies, it is desirable to include relevant international data. Given the international nature of infrastructure investors we believe this approach is justified. It is difficult to understand why arguments are advanced by Ofgem to limit the use of such data, when there are also compelling reasons for disregarding the UK utility comparison data actually used, such as differing regulatory jurisdictions within the same groups, use of water companies as proxies for energy companies, etc. There will always be limitations of any given data set, which is the reason to use all relevant datasets.

FQ13. What is your view on Dr Robertson's report?

We consider Dr Robertson's report to be technical in nature. It highlights how sensitive the model results are to the assumptions used, many of which are highly subjective in nature. Conclusions about the recommended use of a model (OLS or one of a number of variants of GARCH) under a clear set of assumptions are hard to discern. This is unsurprising, as there appear to be no clear "correct" answers to this analysis; rather a spectrum of subjective "possibilities" that may or may not deliver a reasonable answer. It appears that outcomes are very dependent on model specification.

As noted in FQ12 above, our view on the approach that should be taken to estimate equity beta is fully aligned with the approaches and arguments outlined in Oxera's February 2018 ("The cost of equity for RIIO-2") and May 2018 ("Review of Ofgem's initial cost of equity proposals for RIIO-2") reports. These advocate the use of daily data over a time period no greater than five years to avoid the problem of including data points that may not be representative of the current systematic risk of the business.

We would suggest that in order to justify the departure from established regulatory precedent, i.e. using OLS, a timeframe no greater than five years and high frequency data, requires clear demonstration of a superior method that delivers consistently more accurate results. We do not believe that the technical detail presented by either UKRN, or similar from Dr Robertson, meet the necessary hurdle to show GARCH (or one of its many variants) is superior to established regulatory assessment techniques using OLS.

A forthcoming Oxera report for the ENA examines in further detail why use of GARCH over OLS is problematic.

FQ14. What is your view on Indepen's report?

Indepen's report demonstrates that there is no clear cut "correct" way of undertaking the equity beta assessment.

Not unlike Dr Robertson's report, Indepen finds that precise model specification is subjective and can result in a number of different outcomes:

> "*The characteristics of the data series are such that making a statistical estimate of a company's/sector's β at a point in time entails a process that is complex and sensitive to several assumptions and potentially subject to bias and inaccuracy*." (Indepen, December 2018, "Beta Study – RIIO-2", section 5.2, p42)

Indepen then go on to say that:

> "*none of the specific approaches we have considered is without significant failings*". (Indepen, December 2018, "Beta Study – RIIO-2", section 5.2, p42)

Furthermore the range of outcomes reported under section 5 of the report is broad, and appears to disregard the British Telecommunications (BT) evidence in its entirety, offering no further justification for removal apart from the fact that Indepen regard it as "significantly" different. Again this appears to be subjective treatment of an upwardly biased beta estimate; an approach that could no doubt be taken to disregard other pieces of downwardly biased evidence.

Of most concern is Indepen's conclusion not to re-gear to the notional company level. This is contrary to the regulatory concept of assessing financial returns at a notional company level, and is clearly inconsistent with other parts of the regulatory assessment process, most notably for the cost of debt.

Similar to the FQ13 response above, we recommend that established regulatory precedent should be the starting basis for any such analysis, absent any compelling evidence of a consistently superior alternative.

FQ15. What is your view of the proposed Ofgem approach with respect to beta?

As noted in our responses to FQ12 to FQ14 above, we do not support Ofgem's approach in respect of the assessment of equity beta.

In this area we support maintaining established regulatory and CMA precedent, consistent with the approach taken by Oxera in their February and May reports.

An important consideration will be raised in a forthcoming ENA Oxera report on asset and debt risk premiums. This report checks that the sum total of the individual building blocks of the CAPM is consistent with a sensible market-based result. Oxera test this based on the relationship between the asset risk premium and debt risk premium of a company and is based on the principle that any financial claim by debt holders has priority over dividend payments to shareholders. As such, the risk premium to equity holders must be greater than that for debt holders.

The results of Oxera's analysis suggest that the premium differential is below market evidence and that the combination of CAPM assumptions is delivering an extreme result. The recommendation is that one or more of these parameters needs revising upwards to provide a more sensible market-based result.

3.4 Cross-checking the CAPM-implied cost of equity questions

FQ16. Do you agree with our proposal to cross-check CAPM in this way?

We support the concept of CAPM cross-checking however there is a great deal of subjectivity involved in the four proposed approaches which give rise to a range of answers and thereby significantly impact their ability to provide objective support to conclusions drawn from the CAPM.

- **Market-to-asset ratios (MARs)**

  The use of MARs as a cross-check of CAPM as applied within the consultation document is subjective, as we explain below. In addition, any cross checking would need to be done in the context of an overall return position based on a realistic RoRE calculation, and an assessment of the whole regulatory framework.

  The observation of MARs by looking at publicly listed shares is likely to be flawed, due to the small sample size (three companies) and limitations to the water sector and therefore is not directly reflective of the electricity and gas sectors. In addition, the conclusion drawn is very subjective, as acknowledged by Ofgem 'this implies investors *may* expect the return on the RAV to be greater than their costs of capital', as there could be a number of reasons for payment of a premium.

  The observation of MARs by looking at privately held shares is a similarly subjective conclusion. Again, there could be a number of reasons for companies trading at a premium, including future expected synergies and cost savings by the winning bidder. In addition, this data only captures the winning bid, and not the range of bids that were put forward as part of the sale process. The buyer of a business in a competitive market is necessarily reflective of the highest bidders and not a sector average.

- **Professional Forecasts**

  We believe more details are required on Ofgem's analysis of discount rates from listed infrastructure funds, before we would be able to agree with how the professional forecasts have been used as cross check for CAPM, including the following points.

  Closed end funds have different investment horizons to typical energy network investors. This may lead to more weight being placed on shorter term interest rates when calculating discount rates, which may not only explain (in the context of an upward sloping yield curve) why discount rates are low, but also why they have fallen over time by more than might be expected if the discount rates were calculated by reference to very long maturity gilt yields.

  Listed infrastructure funds' discount rates will reflect different levels of leverage. They will not necessarily reflect the leverage of the underlying portfolio of assets, but rather the funds themselves which are likely to be low leverage. Adjusting these discount rates to an equivalent basis to Ofgem's CAPM analysis would likely imply a higher overall cost of equity.

  There may be specific accounting rules that need to be followed in the calculation of these discount rates that mean they do not necessarily reflect the true discount rates of the investors.

  These closed end infrastructure funds have a different mix of dividend and capital growth to investments in energy networks (where dividend yield would typically be lower) and this means that these funds are likely to attract different types of investors (smaller institutional investors) than energy networks and as such may have different discount rates.

These infrastructure funds may hold a more diversified portfolio of investments and as such may not face the same risk profile as energy network investors.

We consider it appropriate that Ofgem validates the analysis by gathering additional data on these discount rates, specifically:

- Gathering discount rates over a longer time series (if the data is available)
- Gathering discount rates for a wider set of funds or investments. To the extent that there are no other listed UK infrastructure funds, data could be gathered for funds listed internationally

- We support Oxera's concern on survey evidence as highlighted in its March 2019 paper ("Rates of return used by investment managers"). It demonstrates that the impact of FCA guidance gives rise to lower advised ranges. In the instances where investment managers have published rates, many caveat their advice and rates by advising that these cannot be used to estimate future performance. Oxera conclude that "if any weight is to be placed on this evidence, the projected growth rates reported therein must be adjusted for the downward bias embedded within such estimates. Academic literature suggests that the adjustment amounts to c. 2%".

- **Bids for Offshore Electricity Transmission Assets**

  We do not believe that the use of bids for offshore electricity transmission assets as a cross-check for CAPM is valid, due to the significant risk and structural differences between networks and OFTOs. Areas where we perceive there to be significant risk differences include construction and longevity of the network assets, asset maintenance, financing, environmental and safety concerns, competition, and the considerably different regulatory and political challenges facing the different sectors.

  Given the above we expect the risk component of the CAPM model to be different and will, therefore, deliver different results.

- **Infrastructure Fund Discount Rates**

  Using infrastructure fund discount rates requires a significant amount of interpretation, with answers differing significantly between the respondents and the context in which the question was framed to them.

It could be found that evidence acquired from different sources may validate a wider range for CAPM, thus rendering the evidence put forward as inconsistent and therefore unreliable.

FQ17. Do you agree that the cross-checks support the CAPM-implied range and lend support that the range can be narrowed to 4-5% on a CPIH basis?

As mentioned in FQ16 above, there is a great deal of subjectivity involved in all of the four proposed approaches which is enabling the cross-checks to support the proposed range of 4-5% on a CPIH basis, however the same cross-checks could also be used to support a much broader range, thereby minimising their usefulness.

FQ18. Are there other cross-checks that we should consider? If so, do you have a proposed approach?

We believe that the overall CAPM outcomes should also be cross-checked against a sensible market-based result for the differential between the asset and debt risk premiums. Please refer to Oxera's March 2019 ENA paper on this subject, and the answer provided to FQ15 above.

3.5 Expected and allowed return questions

FQ19. Do you agree with our proposal to distinguish between allowed returns and expected returns as proposed in Step 3?

We have fundamental concerns with the proposed adjustment to allowed returns.

Firstly, it is imperative that Ofgem accurately measures and evaluates the actual equity returns achieved in the industry. This starts with a full RoRE calculation, adjusting for timing and incorporating all items that may impact equity returns, including financing and tax performance, together with capital structure. This will set the correct context on industry performance and financeability.

Secondly, past performance is not a guarantee of future performance. We believe that the only justification for an adjustment to the allowed return is that Ofgem has *designed* the framework to deliver a target level of out/under performance. This would be incredibly complicated to construct and demonstrate. It would also need calibration across the framework, particularly if Ofgem persists with the implementation of the proposed RAMs. For example, if Ofgem expected companies to outperform by two percentage points and reduced allowed returns to compensate, then the RAM centre points would need to be at AR+2%.

Assuming that any measure of past performance will simply 'repeat' in RIIO-2 is inadequate. The RIIO framework contains all the tools necessary for Ofgem to design a neutral determination, without further adjustment to allowed return. Changes proposed already to RIIO-2 are fundamental. To substantiate any adjustment and retain credibility, Ofgem must provide detailed assessment and justification.

Thirdly, CAPM calculates the minimum return that investors would require for a given level of risk. If Ofgem adjusts for a level of expected outperformance that does not materialise, allowed return will be set below minimum level, potentially, breaching the financeability duty in respect of equity investors.

Finally, if Ofgem introduces this mechanism, it will create future expectations about the calibration of a similar mechanism in future price controls, which will inherently lead to long term investment uncertainty.

We support the arguments presented in Frontier's paper ("Adjusting Baseline Returns for Anticipated Outperformance", *March 2019*) advocating:

- the relative societal benefit of aiming up compared to the harm to consumers of underinvestment; and

- the flawed nature of the theoretical foundations of the MPW report on which Ofgem is basing the allowed 'v' expected return argument.
- that analysis suggests performance is not a one way bet when looked at over a longer period than just the recent price control.

FQ20. Does Finance annex appendix 4 accurately capture the reported outperformance of price controls?

Within appendix 4, Figure 22 is an extract from the Citizens Advice 'Many Happy Returns' 2015 publication. There is no referencing within the document itself as to where the data and performance measures have been sourced, although it is inferred that the data is based on RoRE. Without references such data cannot be relied upon.

The remainder of appendix 4 which relates to the Energy sector using RoRE as a measure of outperformance. These numbers put forward in the remaining data and tables are flawed as they are based on an incomplete RoRE measure which fails to reflect actual company performance at a post financing and tax level as reflected in Ofgem's Annual report 2018.

The information presented in appendix 4 should be represented to use correct RoRE data, including financing and tax performance now that Ofgem has published this data.

FQ21. Is there any other outperformance information that we should consider? We welcome information from stakeholders in light of any gaps or issues with the reported outperformance as per Finance annex appendix 4.

As we note in our response to FQ20 above, RoRE should be measured on an actual, post financing and tax basis to correctly reflect performance of the Energy Sector, in line with the new RFPR Ofgem have introduced. Analysis conducted to date to arrive at performance conclusions in the consultation should be re-considered in light of this updated performance measure.

There also needs to be clarity when distinguishing between returns. The consultation document is not always clear which returns measures are being referred to.

4 Financeability

FQ22. What is your view on our proposed approach to assessing financeability? How should Ofgem approach quantitative and qualitative aspects of the financeability assessment? In your view, what are the relevant quantitative and qualitative aspects?

Ofgem's financeability duty was imposed because Parliament recognised that it was in customer's long term interests to ensure that licensees, absent specific inefficiencies, could attract patient, low priced debt and equity.

While we appreciate the pressure GEMA is under in conducting this review; a course of action that acts to rethink the basis for financing this industry cannot be continued without widening this debate to the whole of Government. Global investment into this sector has been a huge success for thirty years, and policy departures that change this will need as wide an audience and as strong an evidence-based case for change as possible.

Adopting a simplistic, all sector approach could easily result in efficient companies who may suffer from an accident of timing becoming unfinanceable, thereby increasing the perceived risk by investors of the sector, to the detriment of customers.

Ofgem should consider the financeability of each network company individually, taking into account company specific information, including derivative positions and other extant circumstances.

As the need to attract and retain capital applies equally to debt and equity, the financeability duty and therefore the approach to assessing financeability is applicable to both components.

The cash flow floor mechanism has been designed to give reassurance to one group of capital, to the possible detriment of the other.

In paragraph 4.12, Ofgem states its intention to focus on 'notional companies' in assessing financeability. We note that Ofgem, in its March 2018 RIIO-2 Framework Consultation (7.4), stated that it will set the baseline allowed return in RIIO-2 to ensure that an efficient, notionally geared company is able to finance its regulated activities through both debt and equity. This assessment is potentially very different to a 'notional company', which implies that all aspects of a company's performance and position are average, rather than simply its gearing level. Ofgem should provide clarity on this point.

We believe that considering financeability, based on a notional company, without regard to licensees specific circumstances is likely to result in a worse outcome for customers and regions in the long term. It will either result in customers paying more than would be needed to meet a sector's debt costs, or it will create financeability issues for certain networks, resulting in service delivery instability, higher longer term bills and the negative consequences associated with delayed or reduced investment.

In formulating its methodologies, as we have noted before, Ofgem should carry out impact assessments on each licensee to ensure that its proposed methodologies leave all licensees financeable.

Historic corporate financing decisions were based on the regulatory environment at the time and all networks have ensured financeability to date.

As the financeability duty applies to both debt and equity investors, requiring investors to ensure the financeability of debt investors, without regard to the financeability of equity, is not desirable nor is it in line with Ofgem's financeability duty.

For networks that operate close to notional gearing, considered to be an efficient reflection of competitive market capital structure, financeability issues created by the RIIO-2 regulatory package will be considered by the market to be more reflective of inappropriate economic design or calibration.

Requiring that networks delay dividends, or investors inject more equity is value destructive to equity and therefore to the long term financeability of networks. Pension fund investors in particular, are sensitive to such changes. This would undermine the confidence in the UK regulatory system.

To request that Ofgem should instead set allowances at a sufficient level to ensure company financeability does not equate to asking consumers to compensate companies for poor financing decisions, it only reflects the need for businesses to have sufficient headroom available to be able to withstand periods of uncertainty.

We would reiterate that it is in the long term interests of consumers to ensure licensees are financeable. Ofgem should be clear to ensure that consumers' interest in the long term receive as much attention as their interests in the short term, recognising that its duty is to take consumers' interests as a whole.

We agree that financeability needs to be assessed in the round, including all aspects of the price control. It should be based primarily on quantitative measures, but it is also correct to consider qualitative measures.

To grant an investment grade rating, agencies typically discount outperformance to reflect uncertainty, while also requiring some performance headroom to protect downside risk. Ofgem should be mindful of these factors when constructing the overall regulatory package.

Key quantitative measures include PMICR (including Fitch's nominal definition), FFO/net debt (including lease-adjusted figures), absolute post-financing and tax returns and variability in those returns.

Key qualitative measures include regulatory confidence, political uncertainty, and RAMs uncertainty.

We do not believe the cash flow floor mechanism as proposed will ensure investment grade ratings for networks. It is not clear that it is in the interests of consumers and other stakeholders particularly in the long term. Financeability should be assessed and ensured without the cash flow floor mechanism.

FQ23. Do you agree with the possible measures companies could take for addressing financeability? Are there any additional measures we should consider?

Ofgem has a duty to ensure financeability for both debt and equity holders. Neither debt nor equity holders should be required to disadvantage themselves for the benefit of the other.

We do not agree that the onus is solely on equity holders to solve financeability concerns, particularly when those concerns arise as a result of the regulatory environment. It was to both avoid (and to assure any equity investor that it would avoid) financeability issues arising from an inadequate regulatory settlement, that the financeability duty was placed on Ofgem by Parliament.

Companies should only be required to take such action when financeability is threatened from elements within the company control (e.g. inefficiencies).

Mechanically, we are in agreement with the ways listed that companies could address financeability, however we disagree on the grounds that it is not in the long term interests of consumers.

Restricting dividends, equity injections and re-financing of existing debt would materially impact overall equity returns. Dividend policies take time to have material impact and there is limited scope for such restrictions to be effective for issues arising on RIIO-2 implementation.

Refinancing expensive debt is, at best, NPV neutral. This is arguably just a variant on adjusting dividends and equity injection. Future returns need to be attractive enough to attract equity for the long term.

If Ofgem place the onus solely on equity holders to address financeability concerns, we believe there is likely to be a very negative impact on the long term attractiveness of the sector for investors. This would be particularly damaging for post-Brexit Britain.

The economic policies underpinning the finance elements of the framework should be reflective of competitive markets and balanced forecasts, not be distorted to reflect short term reduced consumer bills at the expense of their long term impact.

Infrastructure funds and pension investors target stable, RPI linked, positive returns. Pension funds are the long term providers of patient capital which require inflation-linked returns above RPI. This is specifically RPI, and not any other inflation measure, as RPI has been frequently written into UK pension trust deeds as the inflator for pension liabilities.

FQ24. Do you agree with the objectives and principles set out for the design of a cashflow floor?

The price control should ensure financeability without the need for any additional mechanism.

The financeability duty covers both equity and debt, and the cash flow floor, as structured, would protect debt only, while carrying additional risk for equity holders.

It is essential that Ofgem considers the appropriate counter-factual when assessing the benefits of policy decisions. A safety mechanism will always be viewed as a benefit in isolation, but it should never be considered separately from the danger that is otherwise being introduced through other mechanisms. In this instance, the threat to financeability that is being introduced from removing any headroom from the cost of equity determination.

In addition, by defining its financeability duty by the performance of notional companies, Ofgem is seemingly setting a financial framework that will place certain companies in an unavoidable and financially precarious position. It is then requiring equity investors to introduce more capital to rectify, while justifying this approach with the introduction of a bailout mechanism.

Reducing the equity allowance as proposed will result in less headroom to deal with downside scenarios and this will be considered credit negative for the sector, as Moody's states "If a mechanism is eventually devised that successfully removes the need for Ofgem to allow any headroom to financing costs, the credit quality of the sector is likely to be weakened." (Credit quality likely to weaken in RIIO-GD2 regulatory period, *14th February 2019*). We believe a 'fair' price control would be sufficient to ensure financeability.

The effect on customers of a company failure or indeed, the indirect impact of a punitive price control (reduced investment, less innovation) is potentially more significant than the potential benefit gained from short term reduced equity returns.

The cash flow floor is based on actual company projections, not those of the notional company. Ofgem acknowledges here that it needs to consider actual performance of companies, however only intends to assess its own financing duty on a notional basis. This approach would appear to be disjointed.

We encourage Ofgem to define ‘material company underperformance’. If a company were to trigger the cash flow floor based on baseline performance, with no incentive revenue, this would imply Ofgem has failed to comply with its financeability duty, potentially resulting in legal claims from equity holders.

Regarding the definition of Expected Cash Available (ECA), we believe this measure must only include committed facilities, excluding those from related parties. Ofgem should not allow companies to assume that they can simply raise finance in the future to cover shortfalls as periods of market instability can threaten this assumption and undermine the process.

Ofgem also need to provide guidance on how inflation should be considered in any liquidity forecast. Inflation will impact operational and financing costs, including accretion, indexation and cash interest. It will also impact RAV projections and forecast incremental borrowing capacity, however we note that these components may be less important if Ofgem restricts the definition of ECA to committed facilities only.

Electricity North West operates with an internal risk management policy of holding eighteen months liquidity. Ofgem’s proposal for a liquidity forecast supports the view that pre-financing of maturing debt is prudent, effective risk management and that it is reflective of market practice. As such, Ofgem must ensure that pre-financing costs are appropriately and fairly reflected in the debt allowance.

As is currently proposed, the definition of Debt Service Requirement (DSR) requires the consideration of collateral postings in the event of a three notch downgrade in ratings. Our debt facilities contain covenants that are aligned with the regulatory framework. A three notch downgrade would place us below investment grade and in default for all agreements and we are unlikely to be alone in this regard. We therefore propose that any consideration of credit rating downgrades must be restricted to a floor of BBB-/Baa3.

We note that the structure is complex and while this should not be a barrier in itself, we also note Ofgem’s reluctance to introduce more accurate mechanisms elsewhere, including debt indexation, on the basis of complexity.

Tariff increases at short notice are likely to be problematic for energy suppliers and may lead to increased volatility in consumer bills. The proposal needs extensive consultation with other stakeholders before proceeding further.

We also propose Ofgem consults with credit rating agencies to ensure that it would indeed have the intended protection on ratings and that therefore the mechanism is effective.

Dividend restrictions may result in defaults higher up the ownership chain. Ofgem should be cognisant that this mechanism could ultimately lead to bond holders owning and controlling UK infrastructure assets.

FQ25. Do you support our inclusion of and focus on Variant 3 of the cashflow floor as most likely to meet the main objectives?

We agree that variant 3 is most likely to meet Ofgem’s objectives.

5 Corporation tax

FQ26. Do you support our proposal that companies should seek to obtain the "Fair Tax Mark" certification?

Yes, we support this proposal and are currently seeking to obtain this certification.

FQ27. Is there another method to secure tax legitimacy other than the "Fair Tax Mark" certification? Could we build upon the Finance Acts (2016 and 2009) with regards to the requirement for companies to publish a tax strategy and appoint a Senior Accounting Officer?

Tax information has been shared previously during the recent ring-fence study and we are comfortable with repeating this at regular intervals.

Ofgem should consider duties specified in FA (2016 and 2009) in its risk assessment, however we do not consider it necessary to incorporate these items explicitly into the regulatory environment.

FQ28. For Option A, how should a tax re-opener mechanism be triggered? Is there a materiality threshold that we should use when considering the difference between allowances and taxes actually paid to HMRC? If so – what might this be?

Any mechanism needs to be symmetrical, and also needs to be based on amounts payable to HMRC, not physically paid to HMRC.

Electricity North West is part of a tax group, with net amount of tax due across the Group being paid to HMRC.

The key area of difference between allowance and taxes payable to HMRC is timing. It is critical that any assessment is adjusted for time differences. We note that this is highly complicated and the time required by both networks and Ofgem to evaluate and consider this complexity should not be under estimated.

Any threshold to adjust should be based on materiality, with a dead-band mechanism.

6 Indexation of RAV and calculation of allowed returns

FQ29. What is your view on our proposal for an immediate switch to CPIH from the beginning of RIIO-2 for the purposes of RAV indexation and calculation of allowed return?

The energy sector averages less than 30% index-linked debt. We currently operate with close to 65% index-linked debt on a post-derivatives basis. As it is not part of a wider group, we have chosen to hedge the RPI exposures arising from the debt allowance mechanism: the mechanism strips out embedded (fixed) RPI at debt issuance and pays variable RPI through RAV accretion. As a result of this hedging, with the switch from RPI to CPI (H) Electricity North West is among the most exposed network to the proposed change to CPIH without any transition mechanism.

Index-linked debt provides inflation protection in price controls. The UK price control framework has for many years been linked to RPI. Our structure is based on effective risk management, not risk taking.

An immediate switch, without transition arrangements, will result in basis risk for networks especially where a licencee has hedged its inflation risk. While an immediate switch may be considered manageable on a sector basis, Ofgem will need to consider individual company positions and impact.

Ofgem is not convinced the proposed change to CPIH without any transition mechanism will have a material impact. We request that Ofgem share its analysis and impact assessment that arrives at this conclusion.

Pension funds need RPI linked debt and it is held to hedge the pension liabilities frequently written into trust deeds as RPI. The market for CPI(H) debt is in its infancy, and CPI(H) debt will not offer this same protection. Therefore the appetite and/or cost shown by pension schemes for such network company debt will be impacted.

RPI-CPI(H) swaps are available, but are costly. If Ofgem is intent on moving to CPIH without a transition arrangement, Ofgem should factor these additional swap costs in to any debt allowance assessment.

We note potential complications elsewhere in price control (e.g. absence of breakeven CPI inflation). These are not inconsequential and should be given due consideration by Ofgem before finalising a decision.

FQ30. Is there a better way to secure NPV-neutrality in light of the difficulties we identify with a true-up?

It is critical that Ofgem deliver NPV neutrality. Any assessment of NPV neutrality needs to consider the actual equity investor perspective. It is imperative that this is based on dividend NPV to ensure that no value leakage has occurred. Ofgem needs to share its methodology to enable proper consultation.

While true-up approaches may indirectly link the price-control to RPI, this is not necessarily undesirable and could benefit transition. Basis risk would also be reduced.

We do not believe that a transition arrangement for the move to CPI(H) should be disregarded.

Value neutrality should be measured at outset and, as a minimum, end of regulatory period. We agree that any true-up mechanism should only remain in-force for one regulatory period.

7 Other finance issues

7.1 Regulatory depreciation question

FQ31. Do you have any specific views or evidence relating to useful economic lives of network assets that may impact the assessment of appropriate depreciation rates?

We welcome the fact that Ofgem are open to exploring further changes in depreciation policy, subject to the economic principal of intergenerational fairness.

Depreciation policy and asset lives are levers that can impact key ratios, including FFO to net debt. To the extent that other changes to the framework for RIIO-2, once seen together as a complete package, may negatively impact the future financeability of the network companies, changes to asset lives and depreciation should be considered.

7.2 Capitalisation rates question

FQ32. Do you agree with our proposed approach to consider capitalisation rates following receipt of company business plans?

We cautiously support the proposed approach by Ofgem to tailor capitalisation rates to individual company requirements following receipt of business plans. It should remain an option, but used only in limited circumstances, as it could undermine intergenerational equity. However, capitalisation rate adjustment can only be of limited value, as significant variation in rates will affect the market view of cash flow.

We recognise that adjustment of capitalisation rates can affect cash flows and financeability and our preferred solution to the prospect of financeabilty problems is to correctly assess and calibrate the regulatory framework in the first instance.

7.3 Notional gearing question

FQ33. Do you have any comments on the working assumption for notional gearing of 60%, or on the underlying issues we identify above?

We note that the consultation document was silent on the subject of notional gearing for Electricity Distribution for both RIIO-1 and RIIO-2, combined with the current ED-1 assumption of notional gearing at 65%. We expect that a separate ED assessment will be taking place in future consultations.

In terms of a separate ED2 assessment of notional gearing, we strongly believe that this should remain at 65% as per the current ED1 assumption.

Consequently, this requires Ofgem to re-gear the value of Beta accordingly.

Electricity North West's current financing structure is based upon a gearing level of 65%, which is designed to align with this long term Ofgem assumption. We have issued long-term debt to match the long life of our assets with varying maturities. If Ofgem were to change the gearing assumption for ED2 we would incur substantial costs aligning our debt portfolio.

7.4 Notional equity issuance costs question

FQ34. Do you agree with our proposed approach to consider notional equity issuance costs in light of RIIO-2 business plans and notional gearing?

We support an approach by Ofgem that tailors notional equity issuance costs to individual companies following receipt of business plans.

This follows from our belief that the existing mechanisms do not compensate adequately for the raising of notional equity.

We believe further compensation would be needed in the event that companies would need to raise equity as a consequence of the transition to RIIO-2.

Without adequate compensation, any change in the notional gearing level will have a significant impact on company valuations, potentially impacting the investor appetite of pension fund investors.

7.5 Pension funding question

FQ35. Do you agree that for RIIO-2 we align transmission and gas distribution with electricity distribution and treat Admin and PPF costs as part of totex?

Yes, we agree that for RIIO-2, the treatment of these costs should be aligned with Electricity Distribution for Transmission and Gas Distribution, as the treatment of these costs should be consistent across all sectors.

7.6 Directly Remunerated Services question

FQ36. Do you have any views on the categories of Directly Remunerated Services and their proposed treatment for RIIO-2?

It is noted that the consultation document outlines proposals for the Electricity Transmission, Gas Transmission and Gas Distribution sectors and is silent on Electricity Distribution.

It is assumed that that Electricity Distribution will be considered separately in future consultations with proposals provided by Ofgem, at which point we will be able to provide our views on the Directly Remunerated Services proposed treatment for RIIO-2.

7.7 Disposal of assets question

FQ37. Do you have any views on the potential treatment of financial proceeds or fair value transfers of asset (including land) disposals for RIIO-2?

We believe the current RIIO-ED1 arrangement, whereby cash proceeds are netted off against totex from the year in which proceeds occur, is appropriate.

Appendix 3: response to Electricity System operator questions

March 2019

Contents

1 Overview

As the Distribution Network Operator (DNO) for the North West of England, Electricity North West works closely with National Grid as the Transmission System Operator. As DNOs are actively evolving to the new role and responsibilities of a Distribution System Operator (DSO) this interaction with other parts of the energy system becomes ever more crucial.

With 2019 seeing the Transmission System Operator completing its legal separation from the Transmission Owner, it is appropriate for the Transmission System Operator to have it's first stand alone price control which is specifically designed to take into account the unique nature of it's business.

We will continue to develop our interfaces with the Transmission System Operator, particularly as the energy sector continues to change to facilitate our customer and stakeholders decarbonisation requirements. Already, during RIIO-ED1 we are working towards finding more efficient whole system outcomes. We are therefore fully engaged in the RIIO-2 process to ensure that an appropriate price control is built which enables the Transmission System Operator to deliver its key functions and is flexible enough to adapt to the rapidly changing energy system and its role within it.

We note that the consultation currently has, in some parts, fairly high level principles and approaches and therefore we cannot provide fully considered responses in some areas without further visibility as to how these approaches could be applied in more detail. We would expect that this new type of regulatory framework including the necessary detail will evolve over the coming months and may require further consultation as the options and details become clearer.

2 ESO roles and principles

ESOQ1. Do you agree with our proposal to maintain the current roles and principles framework for RIIO-2?

We agree that given the nature of the non-asset based Transmission System Operator, having clear roles and principles are an appropriate way of regulating a company of this nature. The roles and principles ensure there is a clear focus and also provide clarity to other stakeholders who need to interact with the Transmission System Operator.

We are not certain the existing four roles and seven principles will remain the most appropriate for consumers as we move towards and go through RIIO-2 which will be a period of change. Ofgem recently consulted on whether any changes should be made as part of the review of ESO performance in 2017-18. At that point Electricity North West felt that it was too early to constructively comment as we have not had chance to see how the current roles and principles are working in practice. Ofgem and the performance panel are likely well placed to consider if any revisions are required ahead of RIIO-2 with input from customers and stakeholders. There is a current consultation[1] (closing 14 March 2019) to merge roles 3 and 4 and change the weighting of the principles for the purposes of the incentives framework. Hence our view is that continuous review will be necessary over the coming years as parties gain further experience of working with the Transmission System Operator on the current basis and also while potentially changes to roles and principles become necessary.

The mechanisms for how any changes to roles and principles might be identified and implemented during the ESO RIIO-2 price control needs to be set out.

ESOQ2. Do you agree with our proposals to keep the ESO's code administration, EMR delivery body, data administration, and revenue collection functions in place for RIIO-2? Do you believe that any of these functions (or any other functions) should be opened up to competition, either now or in future?

Taking each in turn:

<u>Code Administration</u> – we support the code administration function being separated from the current Transmission System Operator core responsibilities and subjecting this function to competition. This may result in a more efficient and better performing code function and it may additionally be conducive to code consolidation depending who would take the work on going forward. We do note that the recent Code Administrator Survey showed improvements, however ESO code activities have been historically and remain the poorer performing in the industry.

It would be prudent to make any changes once the outcome of the Energy Codes Review is sufficiently clear.

<u>EMR delivery function</u> – Electricity North West does not have involvement with this function, and therefore are not able to constructively comment on this area of operations.

<u>Data Administration and information provision</u> – It is unclear from the consultation what is meant by this element of service, and therefore we are not able to comment comprehensively, however we support the Transmission System Operator performing data administration and information provision which is relevant to their role. Any other areas of data administration and information provision which extend beyond their core role should be carefully considered including whether another party may be best placed to provide such a function including a developing DSO/DNO.

[1] https://www.ofgem.gov.uk/publications-and-updates/consultation-evaluation-process-2019-20-eso-regulatory-and-incentives-framework

Revenue collection and pass-through – we broadly agree with the proposed approach for the Transmission System Operator to retain responsibility for collecting and passing through TNUoS and BSUoS costs to market participants.

However, we have identified that some billing activities could be undertaken by DNOs, for example residual charges. We explained this in our 4 February 2019 response to the Targeted Charging Review consultation in terms of TNUoS. If the transmission residual is levied on suppliers directly by the Transmission System Operator then this will require duplication of existing processes and result in unnecessary industry change and cost. Levying the transmission residual through the DUoS tariff may be a more pragmatic alternative that should be fully evaluated.

ESOQ3. Do you consider the ESO is best-placed to run early and late competitions?

We cannot see any specific information relating to the Transmission System Operator running early and late competitions within the consultation. We have addressed this point in terms of principles on our answer to questions CSQ60 - 64 within our cross sector response.

3 Price control process

ESOQ4. Do you agree with our proposal to move to a two-year business planning cycled price control process for the ESO? If not, please outline your preferred alternative, noting any key features (eg uncertainty mechanisms or re-openers) that should be included.

We strongly support this move to a two year price control process and have proposed this approach in our previous framework responses. We believe there is a strong case for this approach, particularly as this will be the first of the Transmission System Operator stand-alone price control periods. It will give the flexibility to evolve the framework based on early learning without locking in to an extended period and also brings an element of alignment with the electricity distribution price control commencement in April 2023. This alignment will allow for any the Transmission System Operator and the developing DSOs to work together to greater unlock and explore whole system benefits from the use of capacity and flexibility markets.

We recognise the requirement to balance flexibility to reflect the changing energy system with the need for the Transmission System Operator to have certainty of funding for longer term activities or capital investment. Any risk the Transmission System Operator becomes short-termist in its plans can be addressed by allowing relevant funding streams to be agreed for longer than 2 years where Ofgem is satisfied this is in consumers interests. We expect some IT projects may fall into a category where a bespoke funding over multiple 2 year periods might be required.

We agree that business plans themselves should cover a longer time horizon than two years to demonstrate how the Transmission System Operator is planning for the future and indicate to stakeholders their potential funding needs. A business plan incentive could be designed to reward longer term strategies that work for consumers as well as rewarding delivery of outcomes at efficient costs.

We would therefore support rolling two year price controls with a longer five year planning time horizon.

We do not think specific uncertainty mechanisms or reopeners are necessary for a two year business planning cycle where the next business plan can capture and adapt as uncertainties arise.

ESOQ5. What stakeholder engagement mechanisms should be put in place for the ESO's business planning and ongoing scrutiny of its performance? Do you agree with our proposal to maintain, and build upon, the role of the Performance Panel?

It is still early in our experience, though based on what we've seen to date we support the role of the Performance Panel. This is working well so we agree with the proposal to maintain and build upon its role. The role should continue to be developed in order to learn the early lessons from the performance review of 2018-19 and subsequent periods.

4 Output and incentives

ESOQ6. Do you agree with our proposed approach of using evaluative, ex-ante incentives arrangements for the ESO?

It is appropriate to have performance based incentives for the Transmission System Operator. We found the call for evidence, followed by the open session ahead of the closed performance panel gave stakeholders a good opportunity for wider feedback and was well signalled.

Again it is very early days in the evolution of the Electricity System Operator Reporting and Incentive Arrangements (ESORI), therefore Ofgem should incorporate the lessons learned for 2018-19 and 2019-20 before setting the final arrangements for RIIO-2. The most recent draft forward work programme that the Transmission System Operator has proposed includes outcomes which are "meeting baseline" or "exceeding baseline" upon which evaluation is then possible. We do not agree with the classification of some of the outputs but expect the process will develop further. The development and shape of incentives should continue to be subject to stakeholder and Ofgem feedback to ensure that the targets are sufficiently stretching and relevant throughout the RIIO-2 period from 2021 onwards.

The roles are currently described in fairly high level so there are some aspects on which we are less clear what sits where within the Transmission Owner and the Transmission System Operator after separation. We expect the licence drafting or other Ofgem document will make this clear or that the separation boundaries have been very clearly defined as part of the separation process which isn't directly referred to in this consultation. Drafting licence conditions historically would be undertaken after the business plan is determined, though as this is a new price control we suggest this work is started earlier given the potential complexity of writing brand new licence conditions and potentially separating out any details from the Transmission Owner RIIO-T2 accountabilities/licence.

ESOQ7. Do you agree that we should continue to apply a single 'pot' of incentives to the ESO, and that this should be a symmetrical positive/negative amount? If not, why not?

We agree that the incentive should remain symmetrical however it does need to be proportionate to the business scale and calibrated on the ability to deliver benefits or cause costs for consumers. The incentive strength should be sufficient to drive the desired behaviours however at the same time not so great as it causes financeability issues.

The recently issued consultation on the 2019-20 incentive framework shares an updated proposed approach while retaining a single pot incentive where the evaluation process and incentive range is carried out per role rather than per principle. This feels like an appropriate build reflecting early learning. We continue to engage with Ofgem and the Transmission System Operator through consultations on this subject.

5 Cost assessment

ESOQ8. Do you agree with our proposed approach to assessing the costs of the ESO under RIIO-2? Do you think we should assess costs on an activity-by-activity basis? How would you go about defining the activity categories? Are there alternative approaches we should consider?

Please see response to ESQ9.

ESOQ9. Do you consider the types of cost assessment activities we outline in this chapter are the right ones? Are there additional activities you think we should consider?

This is a combined response to ESQ8 and ESQ9.

We agree with the proposed approach to assess costs on an activity by activity basis. We also support separating out assessment of opex and capex with clear deliverables against activities. It is important for stakeholders to have transparency of the Transmission System Operator costs and this method provides for this.

Insufficient information has been provided in the consultation on current Transmission System Operator activities and associated costs for us to propose a way of defining the activity categories. We agree that using the principles is probably not appropriate and a functional separation is more workable.

Aspects of the eight categories proposed may have the potential to be opened up to competition, as per the considerations elsewhere in this consultation. The relatively limited activities where this might apply, such as code administration where another party might be able to provide a more appropriate level of service for an attractive cost to stakeholders, need to be separately costed.

We agree with the range of requirements proposed to allow assessment of the Transmission System Operator plan, such as CBA's, qualitative and where possible quantitative expenditure justifications, historical costs, comparators and further detailed assessments as per your section 6.26. In some cases we see Ofgem as best placed to consider efficient costs by virtue of the reporting and data they have held historically. Some of the Transmission System Operator activities might be similar enough to those Ofgem undertakes (administering government schemes for example) so there might be some ability to benchmark against Ofgem's own costs in certain areas.

Monopoly service providers like ourselves and the Transmission System Operator need to add value for customers while simultaneously being as efficient as possible to help manage consumer bills. An activity led view of costs should support being able to measure increased efficiency in established activities being delivered over time. It will also give clarity if and where any new activities are added to show the extra cost of these and also show where any activities are stopped and enable the removal of the relevant costs.

6 Finance

ESOQ10. Do you agree with our proposed remuneration model for the ESO under RIIO-2? Do you think it provides the right incentives for the ESO to deliver value for money for consumers and the energy system? Are there other models you think are better suited?

Please see response to ESQ13.

ESOQ11. Are there any risks associated with our proposed remuneration model that you do not think have been effectively captured and addressed? Do you think that we should put in place any of the mechanisms intended to provide additional security to the ESO outlined in this chapter – eg parent company guarantee, insurance premium, industry escrow or capital facility?

Please see response to ESQ13

ESOQ12. Do you agree with our proposal relating to remove the cost sharing factor? Can you foresee any unintended consequences in doing so, and how could these be mitigated?

Please see response to ESQ13

ESOQ13. Do you agree with our proposal to introduce a cost disallowance mechanism for demonstrably inefficient costs? What criteria should we apply in considering what constitutes 'demonstrably inefficient'?

This is a combined response to questions ESQ10 to ESQ13.

We agree that a RAV approach is not appropriate for the business model of the Transmission System Operator, and therefore other remuneration models should be considered.

There are merits to the annual budget with a margin and sharing factor approach which would incentivise the Transmission System Operator to strive for efficiency in their operations. A mechanism on how inter-year effects would be managed needs working through.

We also see merit at a principle level in the cost pass-through with margin which is Ofgem's proposed approach. Ofgem's illustrative example on how allowed returns would be calculated appears sensible; however it is critical that resulting returns are set a level sufficient to compensate investors adequately for this risk. Returns must be set at an appropriate premium to the risk free rate. This will help attract long-term investors and ensure appropriate capital structures are adopted. Any potential risk that a cost pass-through approach may hold, i.e. due to poor cost management/excessive costs incurred which are within the control of the Transmission System Operator can be appropriately managed via evaluation of performance and ex-post tests.

The risks with the proposed model have been covered within the consultation, and it is appropriate that mechanisms are put into place to manage these risks and ensure there is sufficient scrutiny and transparency of costs.

We would highlight that the Transmission System Operator internal costs are generally small relative to the significant benefit that they may be able to generate for consumers and therefore there is higher risk for consumers should the focus be disproportionately placed on budget and cost management. It is important to ensure an adequate business model that provides appropriate funding for the Transmission System Operator activities in order to allow them to focus on those areas that can generate greatest consumer and system benefits.

The risk that the ESO could not cover its costs should be managed in the most cost efficient manner. In our view, this would typically follow practices adopted in competitive market environments. All options should be considered in more detail, but our initial view is that a financial/capital facility is likely to be the most appropriate. Any Escrow arrangement would need to ensure that the industry is appropriately compensated for locked-up capital.

Moving from a RAV based model that is currently in place for the Transmission System Operator (by virtue of them currently being part of the existing T-1 price control regime) will result in an impact to customer bills. The movement from a RAV based slow/fast money funding route to a likely substantially “fast money” approach will need to be carefully considered. Information on customer bill impacts of the new regulatory approach to the ESO needs to be provided.

Care is needed to ensure that any selected mechanisms work in a complimentary way, not using multiple tools for the same issue, or risking having a regulatory package where elements work against each other. Ex post evaluation and cost disallowance appear to work effectively in the DCC price control, and can be mirrored for the Transmission System Operator, however it is important for the Transmission System Operator to have clear guidance and clarity on any cost disallowance mechanism in order to ensure that they do not take an overly cautious approach to the detriment of customers.

The price control needs to allow for a sufficient level of return in order to attract the patient capital required for a company of this type. It will also be important to ensure the company returns are sufficient to support an investment grade rating.

7 Innovation

ESOQ14. Do you agree with our proposals to retain an innovation stimulus for the ESO, but tailor aspects of this innovation stimulus to take account of the nature of the ESO business?

It is appropriate that an innovation stimulus package continues for RIIO-2 and the Transmission System Operator has an opportunity like other networks to take part in this. The package should allow for joint initiatives with third parties and other sector companies. Particularly as we progress embedding whole system thinking we do not consider there is a requirement for a bespoke innovation mechanism for the Transmission System Operator business.

Should there be evidence presented to build a case for something specifically tailored to the Transmission System Operator then the flexibility of two year business plan cycles is well placed to review such requirement as part of the cyclical process.

ESOQ15. What ESO-specific issues should we consider in the design of the ESO innovation stimulus package?

In line with our response to ESOQ14 we do not believe there needs to be anything specific for the Transmission System Operator in the innovation stimulus package.

Appendix 4: response to Gas Distribution annex

March 2019

Contents

1 Overview

Electricity North West Limited (ENWL) serves broadly the same customer base as two gas distribution companies, Cadent and Northern Gas Networks that operate in Electricity North West's distribution services area. We also interface with the Gas Distribution Networks (GDNs) via a number of industry fora, particularly those convened via the Energy Networks Association. Through these channels we share best practice regarding interfacing with consumers. We have also reached out to the GDN's in our area as part of understanding if there are any whole system opportunities arising from their plans and to identify if there are any electricity distribution related requirements (e.g. electricity connections for local gas fuelled generators). Our response focuses on those aspects where there is an overlap in approach and thinking and should be read in conjunction with Appendix 1: response to Cross-sector questions.

Our comments below relate to each of the sections of the consultation document, rather than specific questions per se. We trust this response will assist Ofgem as it develops its thinking further.

2 Meet the needs of consumers and network users

We welcome the overall package of outputs being proposed and the inclusion of measures on consumer vulnerability and the continuation of stakeholder engagement, customer satisfaction survey, complaints metric and GSOPs. Providing a more structured approach to identifying and responding to consumer vulnerability is helpful. Our preference is for baseline funding and output measures to be set to deliver the levels of service consumers' desire and have a willingness to pay for. Additionally, some element of financial and reputational incentives could be merited because rewarding good performance stimulates companies to focus on the incentivised outcomes and funds any innovation and measures that companies need to undertake to deliver improved outcomes for consumers during the price control period.

GDNs should be developing their targets for the proposed outputs in conjunction with their customers to ensure that the standard of service they are proposing, both as a minimum level and subject to any further incentivisation, is in line with what customers are willing to pay for. The approach to this process should then be subject to challenge by the Customer Engagement Groups and the RIIO-2 Challenge Panel. As set out in our response to the Cross Sector consultation (appendix 1), we believe that these incentives should be absolute, based on a given Group or licensee's performance, and not relative.

We suggest Ofgem and the GDNs should consider initiatives that:

1) Enable and encourage cross-sector working to optimise identification and registration of vulnerable consumers. A 'one-stop shop' for registration of vulnerable or priority service customers is an example of such development.
2) Encourage delivery of solutions to consumer vulnerability where this is best delivered in partnership with other utilities and other relevant partners and support agencies.
3) Encourage companies to partner with organisations to provide enabling infrastructure for rural communities.

Incentives should be set mindful of Groups/multiple licence holders. Within RIIO-1 some incentives and allowances were set that paid holders of multiple licences (i.e. Groups) multiple times effectively for one initiative.

2.1 Consumer vulnerability

We agree that network companies should play an important role in helping consumers in vulnerable situations and acknowledge the work already being carried out by GDNs to support their customers. We suggest the following areas where network companies could be further involved to support the vulnerable customers they serve:

- Data sharing between utilities should be a requirement
- Helping consumers prepare for outages
- Signposting vulnerable customers to appropriate help and support as part of BAU, not just in emergencies
- Collaborating with other agencies statutorily placed to provide support to consumers with vulnerabilities.

We would like to clarify that these services should be provided, 'free at the point of use' but clearly companies will need the efficient level of funding to deliver them and be incentivised to drive performance on these during RIIO-2 through investing in innovation and pushing beyond the initial level of performance. Companies delivering more outputs in areas would still be efficient as long as this can be done at an efficient cost below consumers' willingness to pay, so uncertainty or incentive mechanisms should allow this without the need for a reopener or consumers waiting until the next price control.

In addition, we believe there may be an appropriate role for network companies to provide customers with information relating to energy efficiency, community energy and the transition to the low carbon economy. The development of a CBA approach that considers the whole system impact of investments may determine other areas where it is appropriate for network companies to act as this is the most cost effective approach when considering the whole system implications.

2.2 Consumer vulnerability use-it-or-lose-it allowance

We agree that Option one would be the correct approach to implementing a use-it or lose-it allowance as a flexible strategy. We also agree with the assessment criteria set out.

We support the combined package of incentive and requirements, including minimum standards, which provide certainty for companies and customers alike whilst not prohibiting companies from being responsive, innovative and creative in meeting emerging and changing needs.

2.3 Fuel Poor Network Extension Scheme (FPNES)

As this mechanism is specific to the gas sector, we have no detailed comments to make. Going forward, consideration needs to be given as to how this sits within the proposals to decarbonise heat and should form part of GDNs thinking of whole system solutions to deliver the most efficient outcome for consumers in both the long and short term. The FPNES, through extending the gas network, may be increasing the value at risk of assets that are eventually stranded which needs to be considered in any decisions GDN's make to extend the gas network.

2.4 Guaranteed Standards of Performance

Guaranteed Standards of Performance are used in both electricity and gas distribution but have developed separately. They provide a minimum level of service that customers can expect which is helpful, although these could be incorporated in the licence rather than as statutory instruments going forward. Given the differences between the sectors, we believe it is appropriate that these continue to evolve separately, reflecting the needs of customers that they serve and look forward to working with customers and Ofgem on the proposals when developing ED2.

2.5 Average restoration time incentive for total unplanned interruptions

The approach to interruptions differs between electricity and gas, recognising the inherent differences between the sectors. As such, we have no response to this aspect and expect to see the approach for electricity distribution developed as part of the work on ED2.

3 Deliver an environmentally sustainable network

3.1 Decarbonisation of heat

We think there will be a role for GDNs to support the decarbonisation of heat but agree that it is currently unclear what that should be. We note Ofgem's proposal to not include a dedicated output in this area which may be appropriate given the lack of clarity about what is required. However, we would expect there to be some form of mechanism developed to allow GDNs to access funding and agree appropriate outputs in the event that there is an evolution in policy in this area. In order to avoid GDNs being unduly constrained by regulatory barriers, we suggest this may need to be wider than just Government policy to enable GDNs to respond to their customers' needs. It may be appropriate for such a mechanism to be sufficiently broad to allow GDNs to seek additional funding in the event that other drivers, such as changes to power generation or transport, result in significant changes to their customers' needs.

We support the inclusion of low and no regrets decarbonisation projects within Business Plans where this is in customers' interests meaning the projects have a positive cost benefit case and willingness to pay.

We also anticipate that GDNs will work with other licensees to develop whole system approaches to the decarbonisation of heat to ensure sustainable long-term solutions to meet the needs of customers.

3.2 Distributed Gas Connections Guide and distributed gas information strategies

We produce Distributed Generation connection guides which our customers' value. Hence we expect customers would value gas connection related information. The future of these guides should be informed by those who use them.

4 Maintain a safe and resilient network

Our response to the proposals for NARMs can be found in Appendix 1. The comments below relate to the specifics from the Gas Distribution consultation.

4.1 Repex

As a HSE requirement for the GDNs, we expect Ofgem would allow a sufficient mechanism to provide appropriate funding of this activity in an efficient and effective way.

4.2 NTS exit capacity

We have no response to make in relation to NTS exit capacity.

4.3 GDN record keeping

We have no response to make in relation to GDN record keeping.

5 Cost assessment

Evolving the approach used as part of GD1 for cost assessment for the GDNs Business Plans for GD2 is a sensible approach, particularly given the timescales that are being worked to. We are aware that work has been progressed on cost assessment for GD2. As Distribution Network Operators' have not been full participants, we do not expect this to be precedent setting for ED2.

While we are not well placed to comment on the cost categories being proposed for Gas Distribution, we do note the potential challenge where work potentially straddles two or more areas. Given the current proposals for multiple or blended sharing factors, care needs to be taken that the categorisation of costs does not create unforeseen or unintended consequences in the event that different sharing factors are applied to different cost categories.

At a high level, the principles proposed to assess appropriate cost drivers seem reasonable. However, as with many principles-based approaches, it is how these principles are used that will determine their appropriateness. To that end, we suggest further clarity on how Ofgem expects to develop and use these cost drivers would be beneficial for the licensees as they develop their Business Plans and for the User Groups and other stakeholders to be able to consider and, where appropriate, challenge the GDNs' plans. We agree with the observation that the relationship between cost drivers and network costs may change for RIIO-2 and that this needs to be borne in mind.

We understand and note the proposals to require GDNs to share their claims for regional and company specific aspects with each other and for these companies to be able to comment on each other's proposals. We recognise that some GDNs will be claiming that their fair costs are above average. However, we are unconvinced that this necessarily means that symmetrical adjustments can be made. With regional and company specific claims, licensees are setting out why their costs are likely to vary compared to national forecasted averages. Typically, these averages are across more than just gas distribution and it therefore means that it is possible that all parties could be affected. Shortage of a specific skill, for example, could result in labour costs being increased across all licensees when compared to anticipated movement in wages nationally.

We note the proposed timeline at the end of this section for the development of the Business Plan templates and observe, based on our experience, that it can be very time-consuming and challenging for Ofgem and licensees if there are significant changes between different iterations of the BPDT templates. This will be particularly so for RIIO-2 where licensees are taking iterations of their plans to the Customer Engagement Groups / User Groups prior to submission to Ofgem. We suggest that it may be beneficial to update the timeline to show these submissions to the Customer Engagement Groups / User Groups as the timing of these will impact on licensees' ability to respond to updated templates.

6 Uncertainty mechanisms

As set out in our response to the Cross Sector consultation document (Appendix 1), we believe flexibility in the price control arrangements will be essential for RIIO-2 to enable the decarbonisation of the energy system through ensuring the right whole system solutions are taken forward. With an uncertain outlook as to the needs of customers from the gas distribution networks then the price control settlement for gas distribution will need to adapt and be responsive to this increased uncertainty.

We believe that a form of uncertainty mechanism for costs associated with the rollout of smart meters is appropriate to ensure that activities to facilitate this rollout are appropriately funded.

6.1 Review of Agency (Xoserve) costs

We have no response to make in relation to Agency costs.

Appendix 5: response to Electricity Transmission annex

March 2019

1 Overview

ENWL interfaces almost exclusively with the National Grid as transmission owner in England and Wales but does not interface with the Scottish transmission owners other than as required by our network bordering Scottish Power's area. As such our response focuses on those aspects where there is interaction with the TO in England, as well as any overlap in the regulatory treatment that is additional to the topics responded to in Appendix 1: response to Cross-sector questions.

Our comments below relate to each of the sections of the consultation document, rather than specific questions per se. We trust this response will assist Ofgem as it develops its thinking further.

2 Meet the needs of consumers and network users

In developing proposals in this area, it is important that Ofgem is clear regarding the priorities of consumers and networks users and how these may differ from those of stakeholders. We recognise that there are particular challenges in terms of defining incentives in this area where the transmission owners are removed from consumers in many instances, with other participants such as System Operator, Suppliers and Distribution Network Operators (DNOs) like ENWL more directly connected to consumers. However, it is ultimately consumers who bear the costs associated with the electricity transmission network and it is essential that consumer preferences are prioritised when determining outputs in this category with due regard to the value transmission delivers alongside the impact on consumer bills.

2.1 Stakeholder Satisfaction Output

To this end, we are finely balanced as to whether there is merit in the continuation of the Stakeholder Satisfaction Output and the components that form this. At ENWL, we believe that stakeholder engagement is a fundamental activity that should be undertaken to a good standard by all network companies and sufficient provision should be made for this activity within licensees' base allowances. The current incentive framework in electricity distribution has driven improvements in this area during ED1 but we have not tested with our customers whether this should continue to be subject to additional incentivisation in ED2.

As such, we think there is merit in considering more fundamentally whether or not this activity should be incentivised in electricity transmission. We suggest that the companies' business plans should set out the level of stakeholder engagement that they envisage delivering during the T2 period, with transparency around how this can be measured to demonstrate the effectiveness of this engagement.

Mechanisms like the User Survey and KPIs may be appropriate to maintain as a proxy for customer satisfaction and also as inputs to understanding and improving performance, assuming they can be appropriately calibrated and clearly linked to meaningful benefits for consumers. If these are maintained, it should be noted that TOs interface with a number of other parties and not just connecting customers. As such, the survey and KPIs should reflect the needs and priorities of such customers, including DNOs, and consider enduring interactions as well as new interfaces.

2.2 Timely Connections

Timely Connections should be a minimum requirement for transmission owners and this output may therefore be more appropriately classified as a Licence Obligation under the framework proposed in the Cross Sector methodology. On this basis, it should cover all transmission owners.

2.3 Energy Not Supplied

We believe that the Energy Not Supplied (ENS) incentive scheme should be retained as it reflects the marginal valuation of supply reliability by consumers. As noted by Ofgem, it is neither possible nor likely desirable to drive the number of interruptions to zero. Moving to a penalty-only regime infers either a target of zero, or an asymmetrical incentive with no upside which would disincentivise further improvements beyond target levels. We expect that having no interruptions would not be in consumers' interests because of the costs entailed in that level of resilience, though this would need to be investigated.

We highlight that performance improvements are typically a mix of one-off infrastructure investments and ongoing investment in operational measures. If the latter are not funded either under 'baseline' revenues, or incentive returns, then there is a mismatch between allowed costs and expected performance requirements. We also highlight that DNOs are exposed to an element of the restoration (CML) aspect of Transmission level faults and hence we would be concerned with any changes which may disincentivise improved performance and hence potentially lead to a higher level of incidents experienced on the distribution networks.

Due to the lack of comparators in ET, we believe that past performance should be the prime determinant of future targets. We also believe that targets should be set ex-ante to give certainty to both the ET companies and their stakeholders as to the level of performance being incentivised through the period, and to prevent any inadvertent reversals through the period as noted by Ofgem. We agree that a deadband is inappropriate as it does not reflect customer valuation of service.

We are unconvinced that an improvement factor is appropriate for ET. The overall level of service is such and the number of incidents are so low that an incremental improvement factor trending to eventual zero may not be appropriate in face of the significant annual volatility evidenced in Appendix 1.

In using historic performance as the key factor in setting future targets the marginal incentive rate should be aligned with an updated value for VoLL. If an ET licensee includes proposals for ex-ante funding for improvements in its submission, then an appropriate adjustment to its future targets should be made to reflect the expected funded improvements. This would allow licensees to commit to proactive investments, rather than simply reacting to an incentive regime.

We agree that the ENS rate should be based on an updated VoLL value and highlight that it is important that licensees are directly exposed to the assumed impacts of a loss of supply such that their decision making reflects actual economic and social effects.

We note Ofgem's acknowledgement of our current work in this area. We also agree that it is likely to be appropriate to set a single value of VoLL for ET as the scale and interconnectedness of the infrastructure involved means that it serves an aggregated set of customers. We acknowledge that customers directly connected to the Transmission network may have a lower VoLL than domestic customers and hence the ET VoLL value may be lower than the ED equivalent. Our current VoLL work suggests that there is significant disaggregation of VoLL at the SME and domestic customer level such that it is likely that different VoLL both within and between DNOs may be appropriate. We therefore believe that it is essential that the appropriate value for VoLL for electricity distribution be considered as separate from the current decision making process for transmission and that T2 is not deemed to be precedent setting in this area.

We agree that retaining a financial collar for the ENS incentive would seem to be an appropriate way of sharing the risk between licensee and customers. We agree that, given the high levels of absolute reliability, 0MWh represents an absolute upside cap in any case.

We believe that more work needs to be done to look at the feasibility of moving to use of CI/CML measures for incentivising reliability, and that this may be more appropriate for ET3 given the likely scale of data challenges involved. We highlight that moving to an IIS-type measurement will require careful calibration of the CI and CML marginal rates to ensure that major users are not disadvantaged for example.

We agree that specified exceptional events should be excluded, but that the exceptions criteria should be updated. Where appropriate, we suggest that the exceptional event definitions should be aligned with those for DNOs to ensure a consistent approach and valuation, particularly relating to the 132kV network which is part of distribution in England and Wales but is under the TO licensees in Scotland. Discussion on exceptional events needs to be related to any proactive resilience investments proposed by the TOs as it may be that proactive investment is balanced by changes in thresholds.

3 Deliver an environmentally sustainable network

3.1 Environmental framework - Business Plans and annual monitoring

In developing their Business Plans, we believe TOs should give consideration to the environmental impacts of their activities. We expect that the plans submitted would as a minimum ensure compliance with all relevant legal and regulatory standards in this area. Where licensees wish to go beyond these minimum standards, the costs associated with this enhanced delivery should be scrutinised qualitatively in narrative and quantitatively in the form of consumer willingness to pay.

We suggest that the Cost Benefit Analysis (CBAs) used to inform decision making should capture the wider environmental impacts of projects and benefits that are realised by other parties, including end consumers, should be factored in. However, given the scale and cost of transmission infrastructure, it may be more appropriate to maintain existing assets but seek alternative means of delivering solutions to customers' needs, including via non-technical solutions and delivery at distribution voltages. It is therefore essential that sufficient flexibility is in place within the TOs' plans to allow alternative approaches to be considered and, where appropriate, utilised as this may often have a lower environmental impact than traditional TO asset-based approaches.

We do believe there is merit in increased transparency regarding the impact of transmission networks on the environment and annual reporting in this area could assist consumers and stakeholders understand and evaluate the actions being undertaken by TOs. However, we are mindful of the number of reports that are currently required under the transmission licence and suggest that a single public-facing reporting requirement that clearly sets out the licensee's performance against its Business Plan would be preferable to the current myriad of documents. In the event that Ofgem pursues this approach, an evolution of the Business Plan Commitment reporting currently utilised in electricity distribution may be beneficial. We would be happy to discuss our thoughts on how this approach could be evolved if beneficial.

3.2 Potential for bespoke ODIs around the low carbon transition

We believe that it is important that network companies play a proactive role in the low carbon transition, responding to the needs of their customers and stakeholders. However, we are unclear what additional ODIs may be required, either for electricity transmission as a sector or on a bespoke basis for one or more transmission licensee that will deliver additional value for consumers. In order to be able to form a more meaningful view, further information on the nature of a potential ODI is required. In setting any bespoke ODI's around the low carbon transition these will need to be flexible for the timing and nature of any interventions consumers require and a careful balance will need to be struck so that ODIs do not actually incentivise what turns out to be the wrong thing as the low carbon transition unfolds and DNOs bring forward their business plans.

3.3 SF_6 and other insulation and interruption gases (IIG) leakage

ENWL has no response to make in relation to SF_6 and other IIG leakage.

3.4 Electricity losses from the transmission network

As part of taking a whole system view, we believe consideration should be given to carbon impact of decisions. With increasing levels of low carbon generation, reducing losses has the potential to reduce the marginal plant requirements which is increasingly more carbon intensive than alternatives. To this end, we believe that network companies, including TOs, should be required to consider an end-to-end carbon reduction strategy as part of investment decision making and the potential impact of losses should be part of this.

At this stage, we do not have a view on whether improving the metering and energy efficiency of substations is in consumers' interests. However, a CBA approach that considers carbon impacts on a whole system basis would inform a view on whether or not such investment is in consumers' interests.

Increased transparency regarding how TOs are making these decisions would be beneficial and also allow other parties to learn from the actions undertaken by TOs. We agree that there may not be merit in requiring the TOs to issue an annual losses report. However, we suggest that a single overarching performance report, as discussed above in section 3.1, could include significant developments in this area.

3.5 Visual amenity impacts of transmission infrastructure

We agree that this seems appropriate as stakeholders need to be fully engaged in the consultation process and greater transparency of the decision-making process should be welcome.

We agree that mitigation measures in highly sensitive areas can have a significant impact on the visual landscape and improve amenity. For those areas where the visual landscape is a key part of their economic offering, this can also have a positive economic impact.

We also agree that sizing the ET2 provisions must take account of contemporary customer willingness-to-pay for improvements. We highlight however that this willingness-to-pay should not be restricted to Transmission infrastructure only, but should account for all electricity overhead line equipment, including that of the DNOs. Potentially, due to the extremely high cost of mitigating Transmission overhead lines, far more cost-effective visual amenity improvements can be achieved by mitigating DNO equipment, which can also include steel tower routes. Also because of the bespoke nature of transmission projects for visual amenity, the site specific willingness to pay compared with the specific project cost should be investigated, especially where solutions involve high cost engineering such as cable tunnels in one area where lower cost mitigation measures might suffice elsewhere which have a better willingness to pay to cost ratio.

We note that the existing ET mitigation programme results in highly targeted and relatively restricted undergrounding, which leaves large areas of the country untouched (the North West for example). We suggest that an equivalent level of funding for the DNO undergrounding scheme would not only generate greater overall amenity benefit, but a far more diversified one, ensuring that all areas of the country benefit. Taking a whole system approach to this output area could deliver significant benefits for consumers if appropriately managed.

We agree that the scope of the mitigation programme is more foreseeable within a five-year price control period and likely to be identified further in advance due to the planning timescales for Transmission infrastructure projects. However, we are unaware whether the ETs currently have projects identified to a level of detail that would enable the identification of a specific Price Control Deliverable (PCD) in this area. Given the bespoke nature of each visual mitigation scheme, the price control deliverable should be set in tandem with setting the efficient cost allowances.

We suggest that the balance between high and low-cost mitigation projects is not set in advance, unless evidenced by customer willingness-to-pay. Any cap on low-cost solutions would be arbitrary and would not recognise that the identification, planning and delivery timescale for these works is generally far shorter than that for engineering solutions. The low-cost mitigation works also allow a far wider implementation of improvements than engineering solutions alone which, as noted, leave large areas of the country without any benefit.

We agree that the scope of the programme should remain restricted to Designated Areas. These are usually designated on account of their visual appearance in the first place; hence the impact of above-ground infrastructure is usually greater in these areas. However, we suggest that consideration could be given to the equivalent of the 10% rule used in electricity distribution which enables the utilisation of a portion of the undergrounding entitlement outside of Designated Areas, as long as it is appropriately supported by the relevant stakeholders.

3.6 Environmental Discretionary Reward (EDR)

We support the removal of this incentive in its current form as we are unconvinced that it presents good value for money for consumers. We are unconvinced that discretionary rewards are as effective as other mechanisms in driving enhanced performance as licensees are unable to build business cases for discretionary investment to deliver change to benefit customers when the potential upside is unpredictable.

We suggest there may be merit in Ofgem reviewing the design of this mechanism to ensure that any lessons that can be learnt from the design and implementation of the EDR for other incentives.

If there is customer and stakeholder support including a willingness to pay for environmental enhancements then an appropriate incentive should be built around enabling and delivering these environmental outputs.

4 Maintain a safe and resilient network

4.1 Safety

We support the view that the Health and Safety Executive (HSE) is the most appropriate body to regulate safety performance and therefore support the proposed approach set out in paragraph 5.6.

4.2 Network Access Policy (NAP)

We believe there is merit in maintaining the Network Access Policy (NAP) as a means for the TOs to effectively communicate with the ESO and make the necessary trade-offs to ensure timely access to the transmission system for necessary work.

Following the separation of the ESO role from National Grid’s TO function, we do see merit in the NAP covering all three of the TOs going forward. This will increase transparency regarding the interface between the ESO and NGET as TO which we believe is beneficial in terms of mitigating any potential or actual conflicts of interests within National Grid.

At the electricity distribution level, there is a different working relationship with the ESO. Whilst there is merit in increasing communication and co-ordination between the ESO and DSO/DNOs, we are not convinced that this is driven from the same challenges that are behind the NAP. As such, we do not consider it will be beneficial to extend the NAP at this time and suggest alternative communication channels may be more appropriate going forward. We suggest that the outputs from the Open Networks work streams should inform this going forward; with further consideration given as the ED2 control develops.

4.3 Successful delivery of large capital investment projects

We support the development of clear PCDs around the successful delivery of large capital investment projects. The use of a milestone-based approach seems to be appropriate but we would expect this to be considered on a case-by-case basis.

We agree that companies should not benefit from delays to large projects that are needed by consumers, especially where there is clear and demonstrable detriment to them. If a consumer need changes and its economic and efficient to stop or delay work on a large project then this should equally be considered by the TO. However, the RIIO-2 framework is we understand seeking to be a lower fair returns framework with lower risk for companies. As such Ofgem needs to be mindful that its proposals do not inadvertently increase the risk borne by TOs as this could potentially increase costs to consumers or make large projects less investable.

5 Cost assessment

We recognise that it is more challenging to undertake cost assessment for transmission where the sector is dominated by one company, National Grid TO, as opposed to distribution where comparative regulation works well. We therefore believe it is important that other relevant benchmarks are considered. We also suggest that it is important that a bottom-up in detail assessment of costs is required as well as top down so Ofgem can be confident the costs are justified and efficient. Given the lack of comparators, we suggest that the role for expert review is particularly important for transmission to support Ofgem's understanding of the proposed costs.

We understand the proposed changes to the cost categories and at a high level these seem reasonable. However, we are unclear how some costs, such as operational IT, will map to these.

At a high level, the principles proposed to assess appropriate cost drivers seem reasonable. However, as with many principles-based approaches, it is how these principles are used that will determine their appropriateness. To that end, we suggest further clarity on how Ofgem expects to develop and use these cost drivers would be beneficial for the licensees as they develop their Business Plans and for the User Groups and other stakeholders to be able to consider and, where appropriate, challenge the TOs' plans. We agree with the observation that the relationship between cost drivers and network costs may change for RIIO-2 and that this needs to be borne in mind.

We note Ofgem's observation in paragraph 6.29 regarding TOTEX sharing factors and suggest that it is important that an in-depth assessment of how Ofgem's proposed approach to TOTEX sharing factors is considered to ensure this does not result in distorted incentives for companies.

We note the proposed timeline at the end of this section for the development of the Business Plan templates and observe, based on our experience, that it can be very time-consuming and challenging for Ofgem and licensees if there is significant changes between different iterations of the BPDT templates. This will be particularly so for RIIO-2 where licensees are taking iterations of their plans to the Customer Engagement Groups / User Groups prior to submission to Ofgem. We suggest that it may be beneficial to update the timeline to show these submissions to the Customer Engagement Groups / User Groups as the timing of these will impact on licensees' ability to respond to updated templates.

6 Uncertainty mechanisms

As set out in our response to the Cross Sector consultation document (Appendix 1), we believe flexibility in the price control arrangements will be essential for RIIO-2 to enable the decarbonisation of the energy system through ensuring the right whole system solutions are taken forward. With an uncertain outlook as to the needs of customers from the transmission system, and potentially a continued diminishing role of transmission relative to distribution as decentralisation of energy resources continues, then the price control settlement for electricity transmission will need to adapt and be responsive to this increased uncertainty.

We note that Ofgem has talked at stakeholder events about the potential risk for consumers of locking into transmission solutions as part of RIIO-ET2 when better solutions might be brought forward later by amongst others service providers and ED companies which we believe is a valid concern. We therefore believe that an increased use of uncertainty mechanisms is likely to be required for ET2 with a smaller proportion of costs set as a baseline ex-ante allowance to minimise this risk identified by Ofgem.

In general for National Grid TO in England and Wales the uncertainty mechanisms seem to have worked well in protecting customers. These should be recalibrated and any new mechanisms developed and shared in enough detail so that stakeholders can provide input to them. In developing these, we suggest Ofgem needs to consider how it can satisfy itself that proposals included in transmission are the most cost effective response to a given issue, especially where there may be alternatives that could be brought forward as part of ED2 plans.

We have actively engaged with National Grid TO in respect of the plan they are developing and what this means for the North West. National Grid TO has been active in reaching out to us and has listened to our feedback, including from what we have seen to date taking some of it on board.